

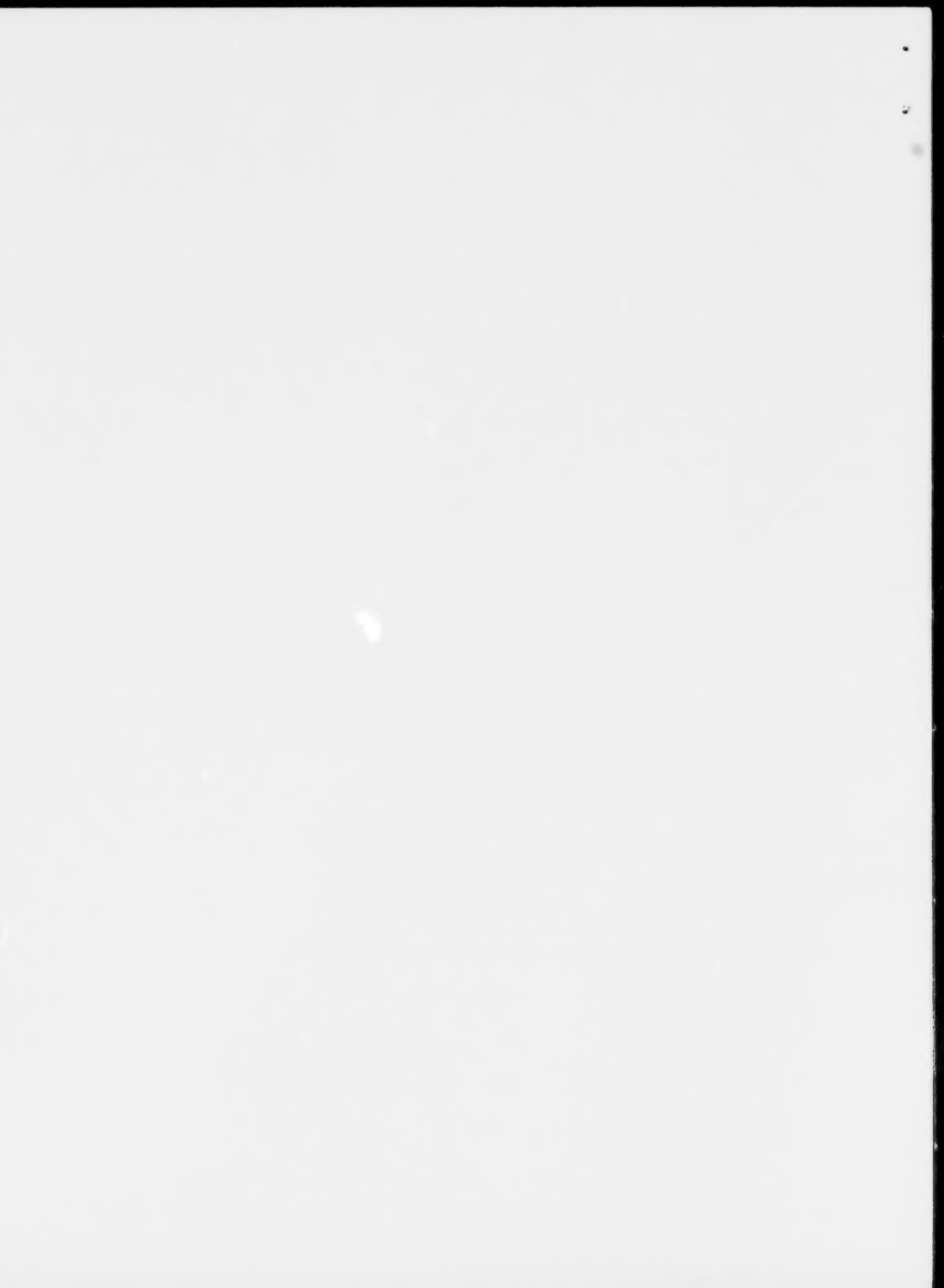
*Our Fair Share*

# OUR FAIR SHARE

Report of the  
Alberta Royalty Review Panel

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To the Hon. Lyle Oberg, Minister of Finance  
18 September 2007



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## ***Our Fair Share***

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September 18, 2007

Honourable Dr. Lyle Oberg  
Minister of Finance  
Government of the Province of Alberta  
#408 Legislature Building  
10800 - 97 Avenue  
Edmonton, AB  
Canada T5K 2B6

Dear Minister,

The Royalty Review Panel ("Panel") that was created to review whether Albertans are receiving a fair share from energy development through royalties, taxes and fees has completed its work. We retained international-calibre expert advice, reviewed previously done work, reached out to all Alberta stakeholders and citizens, vigorously modelled many scenarios and debated what we learned. Given the time constraints relative to the enormity of our mandate, I am proud to report that we, as a Panel, have come together to recommend a mitigating fiscal program that the government can undertake immediately.

We say "mitigating" because our review revealed that Albertans do not receive their fair share from energy development and they have not, in fact, been receiving their fair share for quite some time. Royalty rates and formulas have not kept pace with changes in the resource base, world energy markets and conditions in other energy-rich jurisdictions. Albertans own the resources. The onus is on government to re-balance the royalty and tax system to ensure a fair share is collected both currently and as circumstances change. This must be done within an equitable, flexible and competent administrative framework that maintains Alberta's competitive edge for energy investment while

allowing for all the subjective and objective advantages, including political stability, publicly-funded infrastructure, proximity to markets, and the massive size and certainty of our resource, to name a few.

The Panel's integrated recommendation will achieve the required balance and Alberta's rightful place in international competitiveness based on current conditions. Albertans must have confidence in those chosen to manage their energy resources for maximum yield across several areas: investments, jobs, taxes, royalties and the value-added sector. To secure this confidence, it is essential to provide an enabling and measurable environment in which to create and assess a fair balance between investment by the private sector—the oft-cited “activity” metric—and revenue generation for the owners, or “What’s in it for us?”

There is an absence of accountability from the government to the owners of the resource. Even with substantial effort, Albertans cannot determine whether their interests are being well served and whether or not the royalty system is performing as intended. By recommending an accountability package in the strongest possible terms, the Panel intends that both government and industry will be forced to gather and produce data so that statistics and actionable information can be reported to the owners. We envision disclosure and analysis that is at least as comprehensive, or better, than would be reported to the owners of any major enterprise handling billions of dollars on behalf of its stakeholders every single quarter, let alone every single year.

Some simple but very basic concepts were helpful to us and will be useful to both government and future reviewers of Alberta's fiscal regime in the energy sector. For example, when a government designs a tax system, it must justify every dollar or fraction of a dollar it takes away from wage earners and business, because that money belongs to the people who earned it. Alberta's natural resources belong to Albertans, and this is a different proposition. The design of a royalty and tax system for energy resources therefore must justify every dollar that does not go to the owners. Meanwhile, Alberta must be internationally competitive and developers must be rewarded for their risks and investments. Nonetheless, the fact remains that the resources do not belong to the developers; they belong to the people. This is the Panel's viewpoint and the viewpoint of this report. We believe this viewpoint should also become part of the government and departmental culture with respect to this issue. That this is not the case was demonstrated several times at various points throughout the Panel's analysis.

Over the past 60 years, strategic decisions were made in order to exploit the good fortune that we have as an energy province and those decisions shaped Alberta into the oasis of opportunity it is today. The royalty and tax regime recommended in this report, “Our Fair Share, Report of the Alberta Royalty Review Panel”, represent crucial interim steps toward a new Alberta – one energized by a compelling new understanding of what can be achieved financially and by visionary actions we take now on behalf of our grandchildren and yet-to-be born great-grandchildren.

We proudly and humbly submit this report with gratitude for the opportunity to serve our Province and, in this highly important and strategic arena, I believe this Panel has also served its country.

Regards,

*(original signed by)*

William M. Hunter

Chair

Alberta Royalty Review Panel

On behalf of the Panel

Panel Members:

Evan Chrapko

Judith Dwarkin

Ken McKenzie

André Plourde

Sam Spanglet

## EXECUTIVE SUMMARY

Albertans do not receive their fair share from energy development. The royalty rates and formulas have not kept pace with changes in the resource base and world energy markets. Albertans own the resource. The onus is on their government to re-balance the royalty and tax system so that a fair share is collected. This must be done within an equitable and flexible administrative framework that maintains Alberta's competitive edge for energy investment.

The total government take (Alberta and Canada, taxes and royalties) can be increased with Alberta still remaining an attractive investment destination. The Alberta Royalty Review Panel recommends that the total take for the energy sector be increased by sector, as shown in this table.

	Current Sharing		Recommended Sharing	
	Albertans' share	Developers' share	Albertans' share	Developers' share
<b>Oil Sands</b>	47%	53%	64%	36%
<b>Conventional Oil</b>	44%	56%	49%	51%
<b>Natural Gas</b>	58%	42%	63%	37%

These new targets are lower than the total take of several competing jurisdictions, but are fair in the context of the Alberta resource base and market opportunities. Total government take, once all the recommendations are implemented, will increase by about two billion dollars per year at current price and production levels. This is an increase of 20% over current revenues. See table of Estimated Royalty Revenue Impacts, page 17.

The re-balancing of how royalties and taxes are collected is as important as the total take to the well-being of the energy sector. The recommendations in this report will see royalty reductions for the majority of conventional oil and natural gas wells in Alberta with low production rates, with increases for high-production wells. Price-related royalty caps will be raised since world energy prices have overrun the old caps, with the result that current rates are no longer responsive to market conditions. A production-sensitive component will sustain the competitiveness of conventional wells through the coming years of declining production in that sector.

Oil sands royalties were set at a time when the very few participants in a fledgling industry were struggling. The royalty and tax regime for oil sands no longer reflects a fair share and balance between owners (Albertans) and the growing number of producers. The Panel proposes retaining the core revenue minus cost system (R-C), with the base royalty rate staying at 1%, in view of the significant costs of establishing oil sands projects. The Panel recommends an increased net royalty rate of 33% to apply after project costs have been recovered. In addition, the Panel recommends a price sensitive severance tax (oil sands severance tax, or "OSST"), payable upon commencement of production. The alternative, to achieve the target take only by an increase in the gross and/or profit sharing royalty rates, would place an unfair burden on new entrants to the sector.

The new target rates are designed to close a tax gap between economic sectors, and remain competitive internationally; neither drawing investment in because of 'fire sale prices' nor losing investment to competing jurisdictions with lower total takes. Nonetheless, higher royalties and taxes will slow the pace of oil sands investment.

The Panel recommends against "grandfathering": all recommended provisions should apply equally to all participants, and at the same time. Grandfathering causes market distortions and inequities among participants, which should be avoided. For the same reasons, the Panel strongly recommends that the government consider its options under the Crown Agreements with Syncrude and Suncor, as well as address the transparency problem with bitumen pricing.

The Panel heard from several hundred Albertans, individuals and representatives of companies and organizations who took the time to write submissions to the web site or appear in person. Their input was greatly appreciated and provided a richness and context to the technical data and analyses. The energy industry generally took the view that little in the royalty and fiscal regime needs attention, while the municipalities, non-industry interest groups and the public were nearly unanimous in taking a different view. All sides brought forward their honest concerns for the future, and this reinforced

for the Panel the seriousness of its task. Much of Alberta's economic health will depend on an appropriate royalty and tax regime for the energy sector. Many groups and individuals voiced concerns for the environment and pressures on infrastructure. Those concerns are outside the terms of reference for the Panel and its ability to make recommendations, but they have been conveyed to those who are responsible and remain part of the public record. The full public record may be found at: [http://www.albertaroyaltyreview.ca/public\\_meetings/transcripts\\_submissions.html](http://www.albertaroyaltyreview.ca/public_meetings/transcripts_submissions.html)

In the end, the Panel was guided in its recommendations by the following principles. The tax and royalty regime for the energy industry should:

- retain Alberta's competitive advantage among world energy investment opportunities
- fairly distribute resource income between producers and owners
- be responsive to changes in the economic environment faced by the industry
- minimize distortions in economic activity and investment
- generate a fair distribution of royalties and taxes across producers
- minimize administration and compliance costs while reducing opportunities for avoidance.

The recommendations of the Panel fall into four categories: natural gas, conventional oil, oil sands and administration.

### **Natural Gas and Conventional Oil**

The natural gas and conventional oil sector is the mainstay of the Alberta energy industry, but has matured and now faces declining production. The royalty regime for this sector needs rebalancing to reflect the sector's current state of development and its future, as well as evolution in the market environment for the commodities it produces.

"Fair share" cuts both ways. Among lower production rate wells in the mature conventional sector, there is simply not as much "economic rent" available to be collected compared to the lower-cost, high production rate wells. These recommendations would see 57% and 82% of Alberta's conventional oil and natural gas wells, respectively, paying less in royalties, with the remaining higher-production wells paying more. The royalty impact would be more equitably distributed across the producing spectrum of wells.

The total take is not the only way to look at the royalty and tax system for energy. The current system for natural gas and conventional oil is complex. It grew complex with "patches on the patches", programs and exemptions over the years designed to compensate for, rather than fix, basic problems which emerged as the resource base matured and markets for the commodities evolved. The Panel recommends a significant simplification in the royalty regime for conventional oil and natural gas:



- **Tiers** – That the tiers in natural gas and conventional oil that distinguish “vintages” based on discovery date be eliminated. These distinctions no longer serve a useful purpose and complicate administration.
- **Rate caps on price** – That rate caps on price be raised for natural gas to Cdn \$17.50/MMBtu and for conventional oil to Cdn \$120/barrel. The present caps are so low that royalty rates are no longer sensitive to market conditions. They do not rise or fall with price changes because prices are consistently above the caps.
- **Programs** – That several special royalty programs be eliminated, since the need for them will be eliminated under the recommended royalty formulas. Several programs are “fixes” to reflect the price and cost insensitivity of the old royalty formulas. This is remedied by the new formulas.
- **Formulas** – That the price-sensitive royalty rate and the volume-sensitive rate become separate elements within a single formula. For each of natural gas and conventional oil, replace the current formulas with the following formula, with sliding rate royalty scales (r), for P (price) and Q (well production), yielding a total royalty rate (R):

$$R\% = r_p \% + r_q \%$$

The marginal royalty rate applied to price is  $r_p\%$  and that applied to well production rate is  $r_q\%$ . The maximum total royalty rate payable (R%) for either a natural gas or conventional oil well is 50%. A minimum 2% royalty is payable on natural gas.

- **Use the Natural Gas Reference Price for royalty determination** – That the choice of using Corporate Average Price to determine natural gas royalties be eliminated. Natural gas producers currently can elect to use their Corporate Average Price or the government-determined Reference Price for royalty determinations. The maturation of North American natural gas markets makes this provision no longer necessary.
- **Reclassify existing and future primary oil sands wells as conventional heavy oil wells** – That the option to elect “oil sands” administrative status for primary wells be removed. There are now wells producing conventional heavy oil in “Township 53”, an area identified many years ago as “oil sands” for administrative purposes. Producers in this area will no longer be able to elect to have their well administered under the oil sands royalty regime. This recommendation also appears in the Oils Sands recommendations.
- **Gas Cost Allowance** – The Panel recommends that the Crown deem a fee for processing to apply to all gas processing facilities in the province, with adjustments for the different types of plants related to the nature of the gas being produced (e.g., “wet”, “dry”, and “sweet”).
- **Natural Gas Liquids** – That the recommended royalty formula for conventional oil apply to propane, butanes and pentanes plus, regardless of whether or not these products are stripped out of the natural gas. That the recommended

royalty formula for natural gas apply to ethane, regardless of whether or not this product is stripped out of the natural gas.

- **Freehold Mineral Tax** – That a flat 6% tax apply regardless of level of production. Retain the base exemption of \$1,600.

The simplified royalty framework recommended for natural gas and conventional oil will ensure a fair and stable share of resource revenues for Albertans, sustain the activities of this sector in the many Alberta communities from which it is served, and retain an attractive regime compared to competing jurisdictions with comparable resource opportunities.

## Oil Sands

The generic royalty formula for oil sands projects, the “1% and 25% formula”, was set in 1997 with the intention of spurring investment in an industry that faced an uncertain future. These rates apply to bitumen production, and bitumen is less valuable than upgraded synthetic crude and the lighter oils produced in Alberta. Bitumen is becoming an ever-larger portion of Alberta’s energy production. Combined with passing the peak in conventional production, Alberta faces lower potential royalties in future years, even if energy prices continue to climb. This is because bitumen-based royalties do not yet apply to Suncor and Syncrude, between them representing 49% of today’s bitumen production. This situation changes in 2009 when both of these parties are expected to exercise their Bitumen Royalty Options under their transition agreements, and move from SCO-based to bitumen-based royalties.

Cumulatively, the Panel’s recommended package of changes for oil sands targets a total government take from the oil sands sector of 64%, increased over the present total take which is a little under 50%. Roughly 60% was the total take level identified by the 1995 National Oil Sands Task Force (NOSTF) as consistent with the needs of a fledgling industry. The Panel regards a comparable level of take as more than reasonable for the production powerhouse the sector has become.

As with conventional sources, the circumstances of oil sands production have changed significantly. The fiscal regime (royalties and taxes) needs rebalancing to reflect a fair and sustainable mechanism for future development of a more complex and mature sector with many new participants. The oil sands also face challenges uniquely their own, which need to be worked out between the owners and the developer. Bitumen pricing is an urgent problem for Alberta. Bitumen will be relied upon to generate a growing portion of Alberta’s energy revenues in future years, yet an observable market price on which to base the royalty calculations has not yet developed. A challenge facing producers is the possibility of more charges related to emissions and the environment.

The Panel recommends an integrated package of changes that will increase rates, simplify, standardize and return the system to price sensitivity and fairness:



- **Rentals** – Under current arrangements, oil sands production leases and licenses that remain undeveloped for periods exceeding 20 years face a schedule of escalating rental payments. The Panel recommends that the existing schedule of escalating rentals begin in the sixth year of any agreement (lease or license) and that no deductions be allowed in the calculation of escalating rentals.
- **Base Royalty** - The Panel is of the opinion that the current base royalty rate of 1% remains appropriate for the “pre-Payout” period, in view of the significant costs of establishing oil sands projects. The low base rate gives producers the assurance that, in the event of a major downturn in oil prices, royalties will not represent an undue financial burden for projects that have not yet recovered their initial investment. The Panel thus recommends that the base royalty rate remain at 1%, but that base royalty payments become a deduction in the calculation of the net revenue royalty. This means that for a project in the post Payout period both the base royalty and the net revenue royalty would be payable (as opposed to the current approach where only the “greater of” the base royalty or the net revenue royalty is payable which, practically speaking, means that the net revenue royalty is what is paid).
- **Net Revenue Royalty** - The Panel believes that the current “post-Payout” net royalty rate of 25% is unnecessarily low, in view of the significant changes that have occurred in world energy markets and royalty/tax systems in many jurisdictions over the past decade. It is the Panel’s view that a net royalty rate of 33% would provide a much fairer return to Albertans as owners of the resource, while at the same time ensuring that Alberta’s royalty system remains internationally competitive under a wide range of market conditions.
- **Corporate Income Tax (CIT) and Accelerated Capital Cost Allowance (ACCA)** – In its 2007 Budget, the federal government announced that it was phasing out the ACCA for oil sands in the federal corporate income tax system.

As part of its mandate, the Panel was asked to examine the *provincial* portion of ACCA.

In the federal budget, the decision to eliminate the federal ACCA was justified on the following grounds:

“This incentive [the ACCA] helped to offset some of the risk associated with early investment in the oil sands and contributed to the development of this strategic resource. Over time, however, technological developments and changing economic conditions have led to major investments that have moved the sector to a point where the majority of Canada’s oil production will soon come from oil sands. As a result, this preferential treatment is no longer required.”

The Panel agrees with this assessment. Accordingly, the Panel supports the elimination of the provincial ACCA for oil sands projects.

- **Oil Sands Severance Tax (OSST)** – The Panel strongly recommends that a severance tax, applicable to all oil sands projects, be introduced.

The Panel views the OSST, applying to all Alberta bitumen production, as an absolutely essential component of a “fair” royalty system for Albertans. The Panel recommends:

- That, for each project, an OSST be levied against gross revenues from bitumen production, with a floor applied to the bitumen price equal to 40% of the price of West Texas Intermediate crude (“WTI”) in Canadian dollars. This floor price should remain in effect until a permanent, “generic” bitumen valuation methodology is in place, as discussed below;
  - That rentals, base royalty payments, and net revenue royalty payments be deductible from the base against which OSST is applied;
  - That the OSST rate be linked to the price of WTI in Canadian dollars, as follows:
    - Zero for WTI prices of less than \$40/barrel;
    - 1% at \$40/barrel, and growing by 0.1% for each \$1/barrel increase in the price of WTI;
    - Reaches a maximum of 9% at \$120/barrel, and stays at this rate thereafter;
  - That OSST payments not be considered eligible expenditures for purposes of calculating Payout, revenues for royalty purposes, and income for corporate income tax purposes.
- **Project Definition / Ring Fencing** – The Panel did not gain sufficient data to definitively recommend any changes to the current ring fence mechanism under the Generic Regime. However, the Panel very strongly encourages the Government of Alberta to comprehensively and extensively review and tighten, if required, current rules and enforcement procedures to ensure that absolutely clear, transparent, auditable and appropriate definitions exist for projects and eligible expenditures. If this is found not to be the case in practice—if even to a very small extent—then all pertinent rules, regulations and procedures should be improved accordingly and immediately owing to the fundamental role this principle plays in the design of Alberta’s oil sands Generic Regime for calculating royalties payable by oil sands companies.
  - **Reclassify existing and future primary oil sands wells as conventional heavy oil wells** – That the option to elect “oil sands” administrative status for primary wells be removed. There are now wells producing conventional heavy oil in “Township 53”, an area identified many years ago as “oil sands” for administrative purposes. Producers in this area will no longer be able to elect to

have their well administered under the oil sands royalty regime. This recommendation also appears in the Natural Gas and Conventional Oil recommendations.

- **Grandfathering** – As with all other recommendations in this Report, the Panel makes a recommendation against grandfathering on the grounds of fair treatment for all participants. This issue is treated fully under the *Key Findings* section of the Oil Sands chapter.
- **Bitumen Pricing** – As noted earlier, there are no well functioning markets for bitumen and the interests of Alberta bitumen producers are not all the same with respect to the price received for their product: production-only developers prefer high bitumen prices, while lower bitumen prices (relative to those for SCO) are in the best interests of integrated producers. “Let the market decide” appears unlikely to resolve this issue in the best interests of Albertans.

For hard-to-price commodities like bitumen, formula-based approaches based on published prices for correlated surrogate commodities are common throughout the world as price-setting mechanisms. The Panel believes the Government’s best option rests with such an approach to pricing bitumen.

A permanent, generic “bitumen valuation methodology” (BVM) applicable to all calculations requiring such a value, used by all participants in the exploitation of Alberta’s bitumen resources where a bitumen price needs to be calculated, should be put in place by 30 June 2008. It would replace all current or intended uses of temporary BVMs and alternatives to the permanent BVM would not be allowed.

In very strong terms, the Panel recommends that a truly independent, un-conflicted, world-renowned and highly experienced advisor be hired to consult widely, consider relevant international practices and then develop a permanent BVM. Consultation for this purpose, as a point of clarification, would not entail or imply negotiation nor is it intended to introduce any sense of ‘veto’ power or ‘consent’ requirement on the part of the oil sands industry. As described above, there are simply too many competing interests, too little time left before a BVM is required, and resolving the issue is too fundamental to Alberta’s economy (certainly in the sense of the Treasury of the Province) to continue to leave this issue in limbo or to put the province at risk of hitting an impasse with industry.

The Panel recommends, without limitation but by way of example, that the valuation methodology obtained from this process be applied to all bitumen produced in the province for purposes of determining Payout and for calculating base royalties, net revenue royalties, and OSST payments. Once a permanent BVM is in effect, the bitumen floor price device described above for determining OSST can be lifted, in favour of the new methodology.

- **Expenditures on Environmental Protection and (Currently) Unpriced Inputs** – The Panel recommends that any fees or levies assessed in the future related to the environmental “cost of doing business” for developers and producers be recognized as eligible expenditures for purposes of Payout calculation and in determining net revenue royalties and for purposes of the CIT. Revenues realized as a result of related transactions (such as revenues from the sales of rights, permits, etc.) would be treated as eligible revenues for purposes of determining Payout and calculating net revenue royalties and CIT payments.
- **Upgrader Royalty Credit** – Even though it cannot do so unanimously, the Panel recommends that a tradable royalty credit be introduced at a rate of 5% of eligible capital expenditures on additional upgrading capacity in Alberta. This would only apply for projects whose application to construct and operate an oil sands upgrader is approved by the Energy and Utilities Board (or successor agency) after the bitumen valuation methodology is in place (30 June 2008 as indicated above).

The Panel recommends the following detailed provisions for the proposed upgrader royalty credit:

- The defined purpose of these royalty credits is to encourage the construction of additional upgrading capacity in the province that would not have occurred were it not for the credit;
- It is incumbent on the Government of Alberta to provide the necessary regulatory instruments that would separate, in the case of integrated operations (bitumen production plus upgrading), capital expenditures into those related to bitumen production and those related to upgrading. Capital expenditures related to both bitumen production and upgrading (that is, capital expenditures on physical assets shared between the two functions) are not eligible to earn royalty credits;
- The Panel recommends that qualifying costs for purposes of the upgrader royalty credit be only those costs defined under the *Income Tax Act* (Canada), section 41, and only to the extent that they are directly attributable to new upgrader facilities without allowing for any costs that are shared between, or that are incurred to support, any other types of activity besides the actual process of upgrading bitumen;
- The earned royalty credits can be used to pay royalty obligations by the builder of the additional upgrading capacity or the earned royalty credits can be sold to any bitumen producer in the province (at a price to be determined freely by the buyer and the seller of the credits) which can then use the credits to pay its own royalty obligations;
- Therefore, the builders of additional upgrading capacity can stand to benefit from the availability of the royalty credits as soon as capital expenditures are undertaken and recognized as eligible by the

Government of Alberta. (There is no need for SCO production to begin before the builders realize the financial benefits generated by the credits).

### **Economic and Fiscal Impacts of All Recommendations**

The table below shows an estimated increase in revenue of \$1.9 billion per year when all recommendations are implemented. Calculated at 2006 production and prices this represents an increase of approximately 20% over current estimated total revenues from natural gas, conventional oil and oil sands of \$9.5 billion.

The recommendations will decrease royalties for some projects and wells while increasing royalties for others. Fifty-seven percent of Alberta's 15,931 conventional oil wells will pay lower royalties, as will 82% of the 117,951 natural gas wells. The bulk of the decreases will be enjoyed by low-production wells. Additional revenue, which will more than make up for the decreases, will come mostly from high production rate natural gas and conventional oil wells. Compared to the status quo, the increased revenue projected from oil sands represents a 7% increase in the immediate term, a 38% increase in the medium term, and a 51% increase in the long term.

Detailed financial analyses will be found in the appendices linked through <http://www.albertaroyaltyreview.ca/> modelled from both the owner and investor perspectives.

### Estimated Royalty Revenue Impacts

	Current			Proposed		
Production (see Note)	2006	2010	2016	2006	2010	2016
Gas (Bcf)	5,268	5,059	4,503			
Conventional Oil (Mb/d)	538	469	396		(same)	
Oil Sands (Mb/d)	1,291	2,121	2,726			
Prices (see Note)						
Gas (C\$/GJ)	\$6.22	\$6.34	\$6.18			
Oil (WTI US\$/b)	\$66.22	\$56.44	\$66.60		(same)	
Oil WTI (C\$/b)	\$75.10	\$60.69	\$71.61			
Alberta Government Revenue (modeled)						
Gas	\$5,890	\$4,670	\$2,362	\$6,825	\$5,412	\$2,737
Conventional Oil	\$1,439	\$807	\$551	\$2,252	\$1,263	\$862
Oil Sands under Crown Agreements	\$1,577	\$773	\$1,068			
Oil sands Bitumen	\$627	\$966	\$1,578			
Subtotal Oil sands	\$2,204	\$1,739	\$2,646	\$2,354	\$2,405	\$3,996
Total Revenue to Albertans:	\$9,533	\$7,216	\$5,559	\$11,431	\$9,079	\$7,595
			<b>Change:</b>	<b>+ 20%</b>	<b>+ 26%</b>	<b>+ 37%</b>
				Differences:		
			Gas	\$935	\$742	\$375
			Oil	\$813	\$456	\$311
			Oil Sands	\$150	\$666	\$1,350
			Total:	\$1,898	\$1,863	\$2,036

Alberta Department of Energy, September 2007

#### Notes:

- Internal Alberta Department of Energy ("ADOE") calculations were used for the estimates of the Panel's proposals based on confidential information collected by ADOE through royalty filings.
- Production and Prices based on current government forecasts.
- All estimates are net of government investments in royalty-related incentive programs and of the gas cost allowance.
- These estimates do not reflect the impacts on government revenues of the proposed upgrader royalty credit, which could be substantial if several projects are developed simultaneously. Over the next five (5) years, the Alberta Department of Energy estimates this cost to be \$3.2 billion to the provincial Treasury.
- Some producers pay royalties on bitumen production and others (those under Crown Agreements) see their royalties levied against synthetic crude oil production. The Crown Agreements provide the option for those companies to value royalties based on bitumen prices, post 2008 (the Bitumen Royalty Option, or "BRO"). An estimate of the impact of this switch in valuation is a reduction in royalties of approximately \$800 million per year at current production levels, every year, which is reflected above in the change between 2006 vs. 2010 in the Oil Sands under Crown Agreements row.
- Existing Crown agreements are assumed to remain in place for purposes of these calculations.
- For 2006, production of synthetic crude oil is assumed to be 494 Mbbl/d, while bitumen production is set at 797 Mbbl/d, for a combined total of 1,291 Mbbl/d.



## Accountability

*As agent/trustee for the resource owners, the Alberta Government's role is to collect the "economic rent" associated with the resources (note: the Panel's mandate did not include the coal resource). In practice, this means setting appropriate taxes and royalties, maintaining their relevance over time, and collecting them efficiently. The government is accountable to the citizens of Alberta in fulfilling these duties.*

In the spirit of ensuring that the proposed new royalty structure (or any other regime) lives up to its objectives, the Panel makes the following recommendation in the strongest possible terms: The government of Alberta must implement means to gather and assess the workings of all aspects of revenue policy and collection associated with energy resources in the province. This must be done on behalf of the citizens of Alberta, and its findings must be made public and have the highest degree of credibility. It **must not** be a confidential exercise internal to the government.

The Panel envisions a function and culture similar to that of the Auditor General. In some jurisdictions, a "Super Ministry" or a Deputy leader is primarily tasked with oversight for large, critical and strategic areas like this one that span many aspects of the economy and social realm. Whatever form such a body might take, if the government creates this kind of capability in-house, the funding for this activity would need to be non-contingent (e.g. not subject to political, lobbyist, or other influences) and not trivial as to amount.

Having seen all the competing interests that have a stake in Alberta's energy sector, and the different Ministries that bear directly or indirectly on the revenue that the government can collect from this sector, the Panel feels that the envisioned function would only be effective if it reported directly to the Premier. The work would be presented to the Legislature and this would be done as frequently as any multi-billion dollar corporation does so in any North American or Western European jurisdiction (e.g. quarterly interim reports with annual master reports). Issues and areas addressed by the public reports would include this non-exhaustive list:

- Achievement of targets (e.g. targeted Government Take %)
- A ranking of Alberta's Government Take % relative to that of all other comparable jurisdictions
- An asset catalogue for tracking announcements, construction starts and operational start ups
- Regular reports on costs, materials, labour and seasonal aspects of development
- Information on the impacts of various energy policies (e.g. Upgrader Royalty Credit), both as an expense and as an incremental in-flow.
- Any and all "side deals" and special arrangements or incentives, brought forward to the Legislature for evaluation prior to implementation
- Audit for unintended Royalty leakage in the ordinary course of companies' operations.

The people, institutions and contractors involved in these efforts must be empowered at the highest available level to interact with all Ministries in the government, and also with any and all aspects of the energy companies themselves, again with the same authority levels as the Auditor General.

Standards of compensation and performance of parties involved with this effort would need to be world-class. Notably, given the inherent necessity to constantly be attuned to international standards and common practices regarding royalties, taxes and lease terms in far-flung regions of the world, it would be essential that skill sets of a sufficient depth and number be present in the organization or set of organizations which are discharging this duty.

Capabilities and skill sets needed to staff this function would be very wide-ranging and would need to be extremely senior, preferably with deep prior industry background in natural gas, oil sands and conventional oil. Like a business, critical skill sets to analyze, develop and implement are required to cover off all aspects of exploration, development, operations, and energy sales & marketing. This would include actual operations knowledge and hands-on experience, from geology and prospecting through to refining & transport/pipelines, along with everything in-between.

The use of retired individuals would be advisable, as they will not be threatened or compromised vis-à-vis future industry employment. On the administration/filing side of the equation, skill sets would include legal, accounting, audit (including forensic auditing), and familiarity with tax and royalty calculations and associated filing. As well, statisticians and actuaries would be highly useful, and it would be remiss to not have strong capability to depict complex data and ideas in graphical form. Familiarity with other energy-related legislation and regulation would also be helpful, in the Panel's opinion, and so expertise in the Environmental realm and Municipal taxation would also be an asset.

Given that being internationally competitive with other jurisdictions is one of the cornerstones used to assess fairness, Albertans will need to know how their fiscal regime compares with far-flung, relevant foreign countries. Those countries' legislation, bureaucrats, industry executives, reference materials and public accounts will all need to be consulted. The preceding point would entail not only working across multiple time zones, but also international travel that might be expected in order to perform an on-going assessment of Alberta's ranking of its Government Take % against that of other jurisdictions. All of this makes it self-evident that a deep and complete fluency in various relevant, and sometimes obscure, languages would also increase the effectiveness of this new element of government- and developer-accountability.

As mentioned above, the new independent oversight being suggested by the Panel would be expensive. However, the lack of having such a capability has had consequences that, in the Panel's view, have been very costly along several dimensions. Given the stakes for current and future generations of Albertans, and given the desire to make the outcomes



fair on an on-going basis to affected parties (the resource owner and its agent/trustee – the government – and energy companies), the collective effect of the recommendations in this section represent a very substantial and costly effort. Part of this results from the fact we would be making up for lost time. However, as large as this investment might appear in isolation, it would be a tiny percentage of the value at risk. It would also be more in keeping with the cost to discharge multi-billion dollar fiduciary duties in a typical Western nation.

The Panel believes that investment in this new oversight capability would pay for itself many times over. It will also help to strengthen and sustain citizens' confidence in the system, which the Panel saw called into question many times during the course of its review.

Next, the Panel reaches a difficult recommendation that, while directly applicable to its mandate, may be seen as a betrayal of a department with which it has had to work very closely for the past six months. It is this: Alberta must conceive a go-forward environment for royalty design, maintenance, fairness and effectiveness that is not inherently conflicted in the hands of its functionaries. One seemingly simple, and also obvious, problem that occurred to the Panel throughout its work was that the Alberta Department of Energy is tasked with Mission Impossible. One cannot, by definition, be **simultaneously** responsible for **both** maximizing activity in the energy sector (in terms of rule-setting, licensing policy, etc.) **and also** ensuring that Albertans receive their "fair share" from energy development in terms of royalty terms-design, and audit/policing of royalty compliance. Those two mandates work in opposing directions and tradeoffs against this and other sectors of the economy also come into play. During the public hearing process, the Panel heard many submissions about competing interests relative to the Energy sector.

Related to this point, the government must restructure and redeploy authority and procedures to ensure that spending decisions by the Alberta Department of Energy receive at least as much legislative or Treasury Board scrutiny as spending decisions by any other Ministry. In this context, the Minister of Energy is judge, jury and executioner when it comes to creating special incentive programs or royalty holidays that defer, reduce or eliminate income for the Province. By the same token, his or her department also designs and deploys the royalty programs. This juxtaposition of both regulatory and implementation responsibilities in Energy is different than Norway's approach, for example.

Apart from any required changes to existing Ministries, the Panel acknowledges there may be several ways to source and deploy the resources that could execute some of the government and industry oversight, effectiveness assessment, auditing & public reporting roles envisioned above:

- A sister organization to the Auditor General, but with the above characteristics and mandate, and/or

- A system of two independent, rotating oversight firms similar to that to which Schedule 1 banks must submit, and/or
- Some other international calibre, independent and un-conflicted entity that has deep industry expertise in all the required disciplines, and/or
- A Super Ministry for Non-renewable Resources.

The Panel strongly believes that good intentions must be followed up by meaningful action on the subjects of accountability and stewardship of revenue collection related to Alberta's oil, natural gas and bitumen. This is true not only immediately, but for as long as natural resources remain to be extracted from this territory. The size and importance of the energy resource to Alberta makes this need both urgent and enduring.

The accountability framework would require, at a minimum, that the following reports be submitted to the Legislature and not merely filed internally to the Minister of Energy:

- Effectiveness audits every two years, and
- Annual reports to the owners comprising professional and comprehensive technical, economic and business data, and
- Quarterly statistics on production, prices, developer operating and capital costs (since Albertans allow costs to be deducted before calculating Royalties), collection amounts and forecasts. One starting point for the standards such reporting ought to meet could be the Revenue Source Book of Alaska.

If the Panel's suggested enforcement, public reporting function and accountability culture are not created now, with unwavering commitment from the Government's leadership, one can only hope for a response when the current extent of "data vacuum" and seeming absence of oversight becomes more obvious and more acute to the public at large, as it has to the Panel in the course of its review.

In putting forward these proposals, the members of the Royalty Review Panel express the sincere hope that their recommendations will provide a solid foundation for continuous improvement in Alberta's energy royalty system in the years to come. We believe that, with better information and public awareness of such information, the royalty system can and will become both more accountable and more effective, to the lasting benefit of the people of Alberta.

## **HOW DOES ALBERTA COMPARE?**

This part of the report compares total government take in Alberta and in other energy producing jurisdictions. "Total government take" includes royalties, taxes and fees collected from the Federal and Provincial governments. The total government take combined with the companies' share equals the total value of an energy project. Government take is the standard way to compare among countries. This comparison answers the question "Is Alberta competitive?"

### **Whose take?**

The resources belong to Albertans. The Government of Alberta is their agent and makes deals with developers to produce from those resources. So, revenues received by governments ("take") from energy-producing companies are payments to the owners of the resource. Energy companies do not own the resource; they simply lease the right to produce it.

"Total take" is oil industry jargon. "Economic rent" is economist jargon, and another way to assess fairness that is discussed later in this report.

If a government's total take is too high, companies will move their investments to places where the take is lower. The companies' share must be fair, too.

If the total take is too low, Alberta gives away some of its fair share, and projects of marginal economic value are undertaken just because they are a bargain—i.e. because the "company keep" amounts are too high.

## Comparison Methodology

The government/resource owner share target identified by the Panel as competitive and representing a fair share for Albertans and Canadians ("share" includes Federal Corporate Income Tax) is based on a comprehensive inter-jurisdictional competitiveness analysis. The Panel equally considered the perspective of the energy companies by modeling the various investment decision-making criteria employed by industry. Industry decision-making criteria include rate of return, net present value ("NPV"), and profitability ratio analysis. The results of all these analyses for all the resource sectors (natural gas, conventional oil, and oil sands) and comparable jurisdictions are contained in data appendices which may be found linked through these sites:

<http://www.albertaroyaltyreview.ca/>

<http://www.finance.gov.ab.ca/>

<http://www.energy.gov.ab.ca/>

In addition, the Panel employed third party analysis to validate its recommendations and the Department of Energy's work. This work was completed by Dr. Pedro van Meurs, an internationally recognized expert on the design and assessment of global oil & gas royalty and tax systems. The results obtained by Dr. van Meurs are consistent with the results of Alberta Energy's work; under the Panel's proposed regime, Alberta will remain a very competitive destination for investments in energy projects across all three commodity types in this province.

Note that it was Dr. van Meurs' old 1997 report about international Government Take rankings that was repeatedly cited by industry representatives and energy company executives during the Panel's public hearings across Alberta during the Spring and Summer of 2007. The Panel was constantly told by companies and by energy industry trade groups that Alberta ranked very high in Government Take, but the presenters were citing Dr. van Meurs' old 1997 report. It is true that Alberta had a much higher level of Government Take in 1997 compared to other jurisdictions, but Dr. van Meurs' more recent, up to date, work for the Panel indicates that the very opposite is now unequivocally true: the situation has changed dramatically since 1997 and based on the current situation, Alberta's Government Take ranks very low against competing jurisdictions, especially in the oil sands arena.

All of this data, including Dr. van Meurs' reports, can be found on the listed web sites.

## Comparing the Total Government Take in Alberta and other Jurisdictions

Total government take is used to measure Alberta's ranking among other energy producing jurisdictions. There are different legitimate ways to calculate total

government take. International comparisons are commercially available and often quoted, for example those by Cambridge Energy Research Associates, and Wood Mackenzie. They are all in general agreement as to ranking but can differ slightly in the comparative base. A second reason for cautious use of international comparisons is that total take changes over time and the rankings change. Jurisdictions change their royalty and tax regimes, world energy prices change, and products change, as in Alberta where oil sands have grown in importance. At best, a target for total take is a 'moving target'.

Economic modelling is used to estimate total government take. The latter is not the same as government revenue for a given year. Rather, it is usually given as a percentage, other things being equal, of what that jurisdiction's royalty and tax regime should yield for the life of a project.

Comparison of total government take must be done with caution to make sure comparisons are not of 'apples and oranges'. For Alberta, this means separate comparisons for natural gas, for conventional oil and for oil sands. These are different commodities with different markets and production circumstances. The comparison is less meaningful when, as some have done, they are lumped together.

The comparison charts below are based on the 2007 research prepared for the Alberta Department of Energy by Dr. Pedro Van Meurs, updating his earlier work. (See the technical papers for a discussion of comparisons and methodology at the Alberta Department of Energy web site)

#### Economic modelling

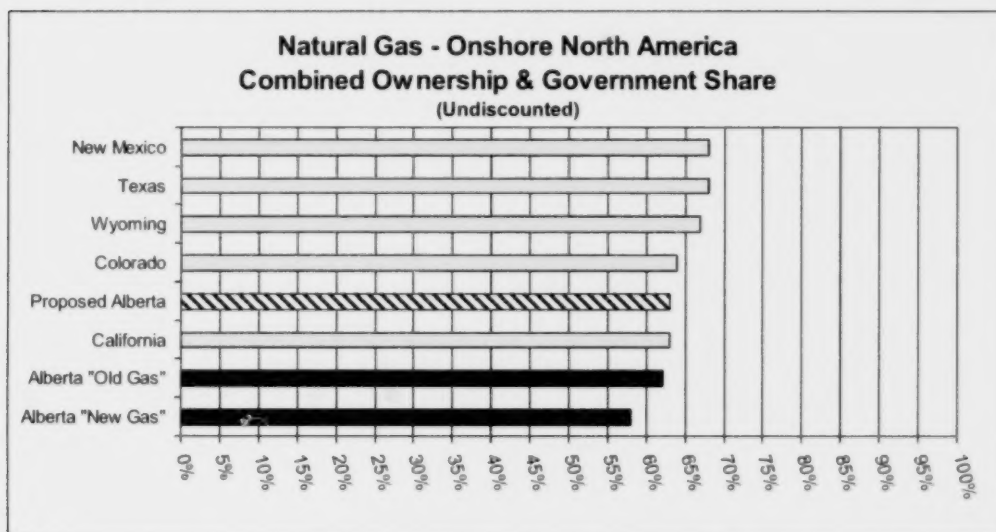
Computer simulation models are commonly used to estimate the total government take from oil and gas activities. These models incorporate an economic approach to modelling oil and gas projects, and include detailed treatments of the key applicable royalty and tax instruments. These are called "project analysis models" and represent the standard methodology for this type of analysis everywhere in the world. For the purposes of this report, models of this type were built for oil wells, gas wells and oil sands projects of different types.

Once the characteristics of "typical" (but not actual) projects are specified (often drawn from past and recent experience with similar projects) and assumptions made about key factors (such as oil and gas prices), the models are used to estimate the level and the distribution of the divisible income, and can thus calculate the total government take percentage associated with these projects. The effects of changes in royalties and taxes on government take are also estimated using project analysis models of this kind.

A limitation of project analysis models is that they provide an incomplete representation of the consequences of various royalties and taxes on the incentives for private-sector investment in oil and gas activities. To address this limitation, this report also includes marginal effective tax rate (METR) calculations, which shed more light on the effects of changes in royalties and taxes from the perspective of energy investors.

For more information on the economic methodology and principles see the Methodology chapter.

The first chart compares the total government take for natural gas in Alberta and several American states selling natural gas into the same North American market. It is constructed to represent economic conditions for "typical" natural gas production projects at a price of \$US 6 - 8 per thousand cubic feet (Mcf) adjusted for differences in distances from markets. Unlike crude oil, natural gas does not come in multiple grades and qualities. This makes a comparison straightforward. Alberta's royalty system currently distinguishes two categories of natural gas production, depending on the discovery date of the 'pool' the well taps. The total government take for Alberta is close to, but lower than, that for the comparative U.S. states.

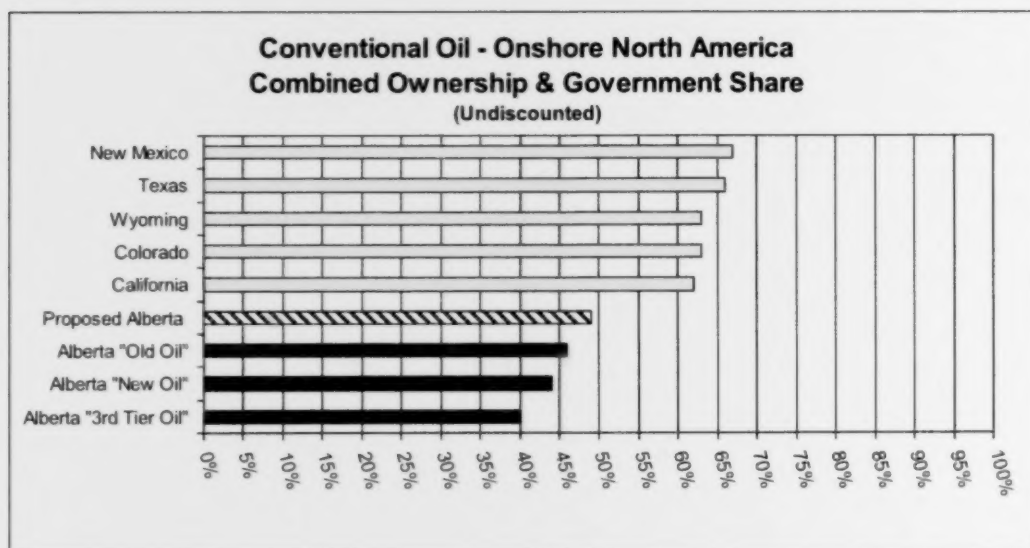


#### Land tenure

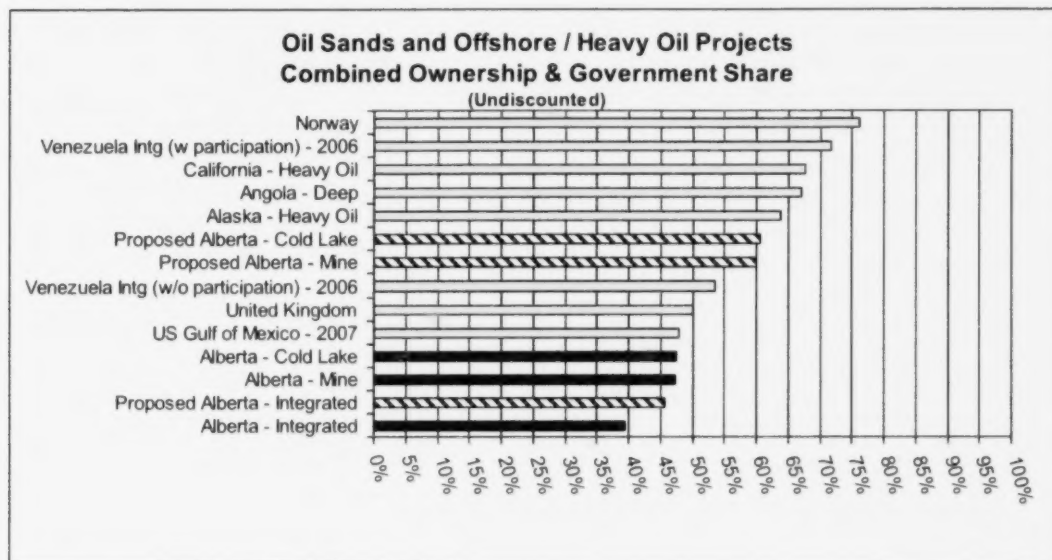
There are differences in land tenure between Alberta and the United States, with most sub-surface rights in private hands in the U.S., while most rights remain with 'the Crown' in Alberta (see the discussion of Freehold Mineral Taxes in the next chapter). As such, it was not the individual states themselves but land owners in those states who negotiated the royalties which are combined with government taxes and fees to produce the total take. That difference is why the charts below are headed "Owner & Government Share".



The second chart compares crude oil (not bitumen from oil sands) with crude oil from the same states as in the natural gas comparison above. The economics of typical projects are here depicted for an assumed light crude oil price of \$US 50-70 per barrel, with due allowances made for differences in oil quality and market location. Again, Alberta has more than one 'vintage' of conventional oil, depending on the date of discovery. This comparison shows Alberta to be further behind these American states in its total take across all three categories of Alberta conventional oil.



The final comparative chart is for total government take on oil sands in Alberta and best estimates for suitable international comparators, given reserve size, investment requirements etc. An oil price of \$US 60/barrel is assumed. This is the most difficult comparison because there is nothing quite comparable to the Alberta oil sands, either in size, in viscosity (it is very thick and will not flow on its own), and in the weather conditions faced by those developing it. The total government take in Alberta varies across projects in Cold Lake (in-situ production), the integrated mine and upgrader projects and the stand-alone bitumen mines. This is explained by differences in the economics of the different methods of production. Again, Alberta is in last place in total government take.



It is worthy of note that a target for oil sands government take was agreed by the NOSTF joint industry and government task force (*National Oil Sands Task Force: A Recommended Fiscal Regime for Canada's Oil Sands Industry, 1995*).

*"A reasonable sharing of the upside marginal revenues is needed to provide balance in sharing of benefits. Thus the retention of a combined tax and royalty marginal rate in the range of 60 percent is reasonable. For the 25 percent and 30 percent NRR (net return royalty) cases, marginal rates of combined tax and royalty are between 58 percent and 63 percent" (page 9)*

Oil sands were then a fledgling industry, yet the target government take set then was higher than the take realized today.

Several presenters to the Alberta Royalty Review Panel cited studies showing that Alberta's royalties were un-competitively high, particularly for oil sands. They gave this as an argument that royalties could not be increased without "killing the goose that lays the golden egg." One such frequently mentioned study was *World Fiscal Systems* (Pedro Van Meurs, 1997), which showed that Alberta was ranked far from the most competitive of jurisdictions. Times have changed, as shown in Van Meurs' 2007 findings presented above.

Comparing Alberta to other Canadian energy producers is not as relevant to the discussion since Alberta's competitors in energy are primarily international. The Western Provinces and Territories have substantially similar royalty and tax regimes, but each with its unique history and applications for differing geologies. A complete description can be found in *Oil and Gas Fiscal Regimes - Western Canadian Provinces and Territories* on the Alberta Department of Energy Website.



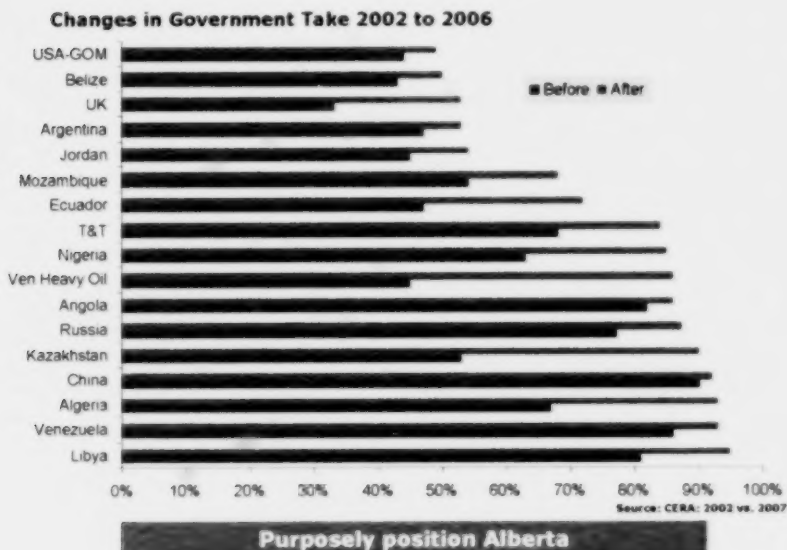
### **Total Government Take is changing around the World**

The charts of total take presented above give a snap shot of something that is actually a moving picture. Total government takes in various jurisdictions have changed significantly over the years.

In its presentation to the Panel on 15 May 2007, Chevron Canada Ltd. provided a helpful illustration reproduced below. This shows the total government take for a number of countries, and the increases between 2002 and 2006. The advice from Chevron, as captured in the green banner at the bottom of the chart, is "Purposely Position Alberta" to keep it competitive. The Panel shares that goal. Alberta's current position (not shown on this chart) would be near the top, among the lowest total government takes currently in the world.

The sense of change conveyed by this chart is useful in understanding the complexity and dynamic nature of the issues involved. Alberta has a lower take now than in years past partly because other jurisdictions have stepped ahead to capture more of the value of the resource that they own, given the run-up in world energy prices. However, as with the other comparisons, it is important to compare 'apples with apples'. A Wood Mackenzie presentation (unpublished) available to the Panel shows some jurisdictions have increased particular aspects of government take, while others have made reductions. Each jurisdiction, as does Alberta, faces its own market and investment situations and adapts to them.

## Assessment of Oil and Gas Jurisdictions is Complex and Continuous



[http://www.albertaroyaltyreview.ca/public\\_meetings/submissions/2007\\_0515\\_mark\\_nelson\\_chevron02.pdf](http://www.albertaroyaltyreview.ca/public_meetings/submissions/2007_0515_mark_nelson_chevron02.pdf)

### Comparing Oil and Gas with other Sectors

The energy sector accounts for a third to a half Alberta's economy, depending upon how it is measured. Forestry, manufacturing, construction, transportation, wholesale, retail and so on, are other sectors of the economy which compete with energy for workers and capital. A question put in the terms of reference for the Panel is how the tax treatment of the oil and gas sector compares with other sectors and jurisdictions.

**METR**

The marginal effective tax rate ("METR") is designed to measure the impact of the fiscal system (taxes and royalties) on the incentive to undertake investment. It does this by determining the impact of a tax applied to an additional, or incremental, dollar of capital. A lower METR means an investment is more attractive.

The marginal effective tax rate on capital is calculated as the expected pre-tax rate of return minus the expected after-tax rate of return on a new marginal investment, divided by the pre-tax rate of return. The METR therefore measures the share of the pre-tax rate of return on a marginal investment that is required to pay the resulting taxes (and royalties). It takes into account the tax laws for each jurisdiction.

The table below shows comparisons of marginal effective tax rates (2004 data, Finance Canada, reflecting tax laws in force as of 2007). Texas is the most direct comparison for Alberta energy because of the similarities in natural gas and conventional oil sectors. Calculations are provided for various sectors in Alberta, Canada, the US and Texas.

For comparison purposes for energy, marginal effective tax rates are presented for two cases, one where royalties are excluded from the calculation, and therefore treated as a cost, and one where royalties are included with other taxes on capital in the calculation. In the case of Texas, landowner royalties are combined with government imposed severance taxes in the "royalties included" calculation.

'METR' IN PERCENT	ALBERTA CURRENT	CANADA CURRENT	UNITED STATES (BY 2010)	TEXAS (BY 2010)
All non-oil Sectors	19	28	24.6	23.2
Forestry	18.3	23.3	20.7	19.6
Manufacturing	18.8	25.6	24.9	23.7
Construction	22	30.3	23.4	22.1
Transportation	16.8	27.1	24.3	23.1
Communications	15.3	23.9	15.6	14
Public Utilities	14.5	20.1	13.7	12.1
Wholesale Trade	25.4	35.2	27.2	26.1
Retail Trade	25.8	37.1	30.5	29.3
Other Services	20.3	30.2	27.2	25.9
Conventional Oil and Gas:				
Royalties excluded	6.6	n/a	n/a	11.3
Royalties included	30.6	n/a	n/a	47.3
Non-integrated Oil Sands:				
Royalties excluded (with ACCA)	3.2	n/a	n/a	n/a
Royalties excluded (no ACCA)	13.5	n/a	n/a	n/a
Royalties included (with ACCA)	5.0	n/a	n/a	n/a
Royalties included (no ACCA)	16.8	n/a	n/a	n/a
Integrated Oil Sands:				
Royalties excluded (with ACCA)	3.2	n/a	n/a	n/a
Royalties excluded (no ACCA)	13.5	n/a	n/a	n/a
Royalties included (with ACCA)	4.0	n/a	n/a	n/a
Royalties included (no ACCA)	14.9	n/a	n/a	n/a

Excluding royalties, and therefore treating them as a cost, the METR for conventional oil and natural gas in Alberta is lower than for other industries in Alberta or Canada. The primary reason for this is the favourable taxation of intangible expenditures on exploration and development. When royalties are included, the METR on capital employed in conventional oil and natural gas increases significantly. This is justified because of the presence of economic rents associated with resource exploration.

In the case of the oil sands, operations that are integrated with an upgrader must be distinguished from non-integrated operations, which have no upgrader. The reason for

this is that in the case of integrated operations, the upgrader component is a manufacturing and processing operation, and not a "pure" resource project. Income generated by the upgrader is not subject to royalties, though it is subject to corporate income taxes. As seen above, the government take from integrated operations is lower than for non-integrated operations; this is also the case with the METR.

Excluding royalties, and therefore treating royalties as a cost, the METR on capital in the case of non-integrated oil sands is lower than other sectors, including conventional oil and gas, especially prior to the phase-out of the accelerated capital cost allowance (ACCA). This is because of the expensing of ordinarily depreciable expenditures on machinery and equipment in the oil sands under the ACCA. The elimination of the ACCA increases the royalty-exclusive METR on capital in the oil sands, but it remains somewhat lower than the effective tax rate in other sectors of the economy.

Including royalties in the calculation, the royalty-inclusive METR on non-integrated oil sands capital before the elimination of the ACCA is very low. Though it increases significantly after the phase-out of the ACCA, it remains low relative to other sectors. For an integrated operation, which includes an upgrader, the METR on capital for the royalty inclusive cases, are slightly lower than for non-integrated operations because the income generated by some of the capital (in the calculations 50%) is not subject to royalties.

The analysis of marginal effective tax rates on capital in the conventional oil and natural gas sector suggests that the current fiscal terms facing the industry are quite attractive relative to other sectors in the economy, and relative to the treatment of oil and gas in Texas. This is particularly true for the oil sands.

**Well drilling equipment tax**

Municipal taxes are not included in calculations of total government take because they are classified as fees for service.

Alberta Municipal Affairs and Housing is currently conducting a review of the Well Drilling Equipment Tax, implemented about 40 years ago to provide municipalities with a way to offset the damage to roads from well drilling equipment and activity.

The Panel supports this initiative.

**Refining and Petrochemicals**

The Panel received presentations addressing the issue of 'value added' that can result from resource processing. For example, refineries add value to the crude they process. So do petrochemical complexes with the hydrocarbons they use as manufacturing feedstock. Upgraders add value by converting bitumen to a lighter type of crude oil. While oil and gas production generates royalties, their downstream processing is outside the royalty system because this is a form of manufacturing. However, the value added by refining and petrochemical conversion is taxed through corporate income taxes.

The Panel considered whether the royalty regime should be expanded to encompass refining and the petrochemical industry. The Panel concluded that a change is not appropriate as hydrocarbon conversion activities such as these do not generate economic rent and therefore are outside the scope of the resource royalty system. The refining and petrochemical industries are not at a tax disadvantage, either, so no change in taxes is required on that basis. As a matter of public policy the government may choose to support a particular effort, as it did with the IEEP (Incremental Ethane Extraction Policy).

Alberta has three major refineries owned by Shell, Imperial and PetroCanada. They are high complexity but medium size ~140,000 barrels per day output. The Alberta refineries supply some product to the Prairie Provinces, though for the most part, Alberta's production and consumption of refined products is in balance. The refineries produce gasoline, diesel, jet fuel, lubricants and chemicals used in the petrochemical industry.

Less sophisticated refineries are unable to economically process a large proportion of heavy, sour crude oils such as Alberta's bitumen blend without adding conversion capacity. As availability of conventional light, sweet oil drops off, refineries in the markets served by Alberta crude producers have been adding conversion capacity so as to be able to accept greater volumes of heavier and sour crudes. Market forces are shaping these changes.

Alberta has a well-established petrochemical industry. The challenges it faces stem from long distances to markets and increased costs of expansion. This industry once had access to inexpensive natural gas as feedstock, but as pipeline capacity expanded, the gas was available for export and its price became set by market forces. Low natural gas prices had been this industry's main advantage, but that advantage has disappeared in recent years as North American natural gas prices have strengthened.

**Conclusions**

Alberta's competitive position with regard to conventional oil and natural gas is excellent. Compared to Texas (typical of American total government and owner take),

Alberta conventional oil and natural gas production is competitive at most price and production levels. Alberta's regime is especially attractive with respect to lower productivity wells. The chapter on conventional oil and natural gas provides detail on these comparisons.

Alberta's competitive position with regard to oil sands appears to be overly generous when viewed against the total government take of other jurisdictions, and the targeted take of ten years ago. This finding must be viewed with some caution because of the particular challenges of oil sands projects, which will be discussed in the Oil Sands chapter.

The tax treatment of the oil and gas sector in Alberta is such that it currently has a material advantage over other sectors in the economy.

The Panel concludes that Alberta can increase its total government take without endangering its competitive position. Recommendations about how to raise total government take, where, and by how much, follow the detailed economic modelling in the next chapters.

## **WHAT WAS SAID**

### **Consultation Process**

The Royalty Review Panel was announced on 16 February 2007 and public meetings held as follows:

- Grande Prairie, April 23-24
- Edmonton, May 14-16
- Calgary, May 22-24
- Fort McMurray, June 4-6
- Medicine Hat, June 18-20

Submissions from individuals and organizations, 224 in total, were received by fax, mail, online, and in person at the public meetings. The Panel heard more than 100 presentations at its public hearings. Some in the press commented on the low turn out to the hearings, but in view of the 56,000 visits to the web site, it appears that Albertans were taking advantage of technology to keep informed of the process.

The public presenters were evenly split between industry representatives and citizens, non-industry interest groups and municipalities. The online submissions were three-quarters from citizens and the remainder from industry, municipalities and non-industry groups. About half the online submissions included attached documentation, while the rest were brief email comments. The Panel's web site served as a portal for submissions and to disseminate information on the royalty system through the links provided to briefing and background papers.

The Panel Web site, all the submissions, transcripts of the hearings and the background documents remain at <http://www.albertaroyaltyreview.ca/>

### **Divergent Opinion**



The Panel heard many divergent perspectives, demonstrating that the royalties and taxes paid by Alberta energy companies, and the activities that generate the royalties, affect the lives of Albertans in very different ways. Directly, and indirectly, activity centered on the energy sector causes concerns and problems, as well as opportunities, for many who took the time to convey their views.

The most striking aspect of the submissions to the Panel was the high proportion of comments that fell outside the terms of reference, and of the scope of recommendations, the Panel can make. More will be said of this later, but the difficulty experienced by many in framing their concerns is indicative of a broader issue of understanding and information about the energy sector, its royalties and taxes.

There is a logical and moral difficulty in separating the activity and the impact of the activity; and in separating the design of the royalty regime from the overall regulation of the economy. For example, many citizens spoke to the Panel about environmental concerns, and many corporate presenters turned to the Panel for comfort against the costs those corporations had chosen to accept.

In the minds of a majority of respondents, the royalty system is, or ought to be, integrated into a broader framework. It is, but not by the design of royalties and taxes. The problem for the Panel with many submissions lies in the notion that royalty rates can be used as a throttle to speed or slow economic development, or to influence industry costs. The Panel takes the view that the royalty and tax framework of the energy sector is not an appropriate mechanism to alleviate pressures on municipal infrastructure or industry costs or other such short-term phenomena. While royalty rates will influence long-term investment trends, governments have more precise, more appropriately sized and more cost effective tools to direct towards short-term policy. The royalty regime cannot respond to short-term developments and simultaneously maintain the desirable stability. Rather, it needs to be a system that is stable across a range of possible circumstances in the future. Maintaining this stability of the whole can, from time to time, require periodic adjustment of the parts. Consideration of whether now is one of those times is the Panel's mandate.

### **Costs and Royalty Rates**

Rising exploration, development and production costs are part of the current Alberta reality. Some companies feel that this reality is a reason to cut or hold steady on royalty rates. The Panel is of the view that costs are the same for all and that it is the mandate of corporate management to control their costs and that they have tools to do so.

The market has worked, those needing labour and materiel have bid up costs, and those resources repositioned in the economy to where they are most valued. The same reasoning applies to costs related to environmental programs. Good management and planning may result in an advantage to some participants, independent of the royalty and tax framework.

Costs are not an argument for or against a particular finding of a fair royalty level. Costs can move fast and for different reasons than those factors influencing a fair share royalty. The impact of foreign exchange fluctuations is a good example. Royalty systems need to provide stability over the long term, not to be adjusted in response to short-term market conditions.

The stories of the presenters wove a complex picture. Many large oil producers were firm in their views that the present arrangements work well and should not be changed. The primary focus of their comments was oil sands. Smaller conventional oil and gas producers, and the service sector, cited disincentives to getting the most from the old, rapidly declining fields widely spread across rural Alberta. Municipalities told a convincing story of infrastructure pressures. Several extraordinary "ordinary Albertans" added colour and detail about the impacts they have experienced and the potential improvements to quality of life they wished to see. The thought they put into their submissions was appreciated and is now part of the public record.

The material submitted on the web site aligns closely, but not completely with the public presentations. Some online submissions had narrow focus and specialized recommendations not voiced in the hearings. The on-line submissions from members of the public focused less on specific spending proposals than did the presenters at the hearings.

Themes emerged. For citizens these were the environment, infrastructure, the pace of development and "value added" jobs. For industry, the need for stability and predictability was most frequently mentioned. Service companies said they were extremely sensitive to changes in activity levels, and concerned for tertiary and older production projects. Municipalities and special interest groups were looking for dedicated funding.

**What was said on the web site**

A brief account of the web submissions gives a flavour for the diversity of comment:

- 55% made declarative observations, e.g. "costs out of control". "1% is a sham", "unconventional is the future"
- 55% made substantive recommendations, e.g. "reduce royalties for low production wells", "no caps, use a sliding scale", "give technical innovation incentives"
- Some issues/concerns appeared frequently in the submissions
 

○ Pace of development too high	16%
○ Environmental damage and need to clean up	15%
○ Infrastructure, roads, health, etc. falling behind	10%
○ Value added jobs	10%
- 15% directly answered the question "Are Albertans getting a fair share"?
 

No	66%
Yes	33%
- 55.9% expressed a direct opinion as to whether royalties should be increased, decreased or left the same.
 

Increase	37%
Decrease	1%
Left the same	18%
- Those favouring an increase were mostly citizens while those feeling royalties should be left the same were mostly from industry backgrounds.
- 12% mentioned "high level" alternative management strategies for both the government take and disposition of royalties, for example, to copy Norway or Alaska, or establish new dedicated funds (e.g. for environmental, infrastructure, or a recommitment to the Heritage Trust Fund.)
- 55% of the comments included advice on "how the money should be spent" as part of their submission. Spending related comments ranged from suggestions for infrastructure, through subsidies to certain sectors, to specialized trust funds. Many of these comments implied, or stated emphatically, that the current situation was not acceptable to the commentator.

**A Vision to Merge Environmental and Economic Leadership**

The Panel knows the limits of its mandate, but would feel remiss not to point out the strength of opinion it encountered voicing the need to manage environmental and economic development challenges as an integrated whole. Several other government-appointed entities have been looking at various pieces of this puzzle during the same months as the Royalty Review Panel's hearings. We do not prejudge their recommendations, nor what will be made of them. We do note that many voices found many ears, none of which appear to have a mandate equal to the scope of the concerns.

The panel considered, but could reach no conclusion, on the merits of apportioning royalty income for the long-range needs to research, understand, anticipate and ameliorate the environmental impacts of development that will surely go beyond the current total financial and action-oriented responsibilities of individual developers.

The future belongs to the leaders who can merge these concerns, or to our children who will live with the consequences if we fail.

**Suggested Directions**

Presentations to the Panel concerning conventional oil and natural gas seem to indicate a general satisfaction with royalty levels. Unconventional gas, the Panel was told, might benefit from some encouragement of research and development within the framework of the present royalty system. In addition, as production drops in particular wells and fields, conventional oil would benefit from royalties sensitive to low well productivities as the "rent" that can be generated from such wells is less. The Panel was not presented with arguments that current royalties were unreasonable, too high, or too low, for the market and resource conditions faced by this segment of the industry.

Oil sands royalties were subject to a much broader range of opinion. Most in the industry took the view that increasing royalties was impossible; otherwise investment would plummet. Some allowed that moderate increases were possible. Citizens and municipalities tended to the view that royalties were too low to cover the costs of the impacts of energy development on community infrastructure and the environment. However, some citizens and business people cautioned against the risk of losing jobs and slowing activity should royalties be raised. Many of these comments were "high level" in nature, rather than explaining how an increase in royalties would have the dire consequences predicted. The Alberta Department of Energy commissioned studies to give an empirical base to evaluate these various arguments over a range of market and sector conditions. These are discussed in the preceding chapter and in the specific accounts of natural gas, conventional oil and oil sands.

## **The Industry Position on Royalty Levels**

This news release from the Canadian Association of Petroleum Producers (CAPP) and the Small Explorers and Producers Association of Canada (SEPAC) on their joint presentation to the Panel provides a useful and concise summary of the themes in the many hundreds of pages of industry presentations (found on the CAPP website at <http://www.capp.ca/>):

CAPP and SEPAC Release Report on Alberta's Oil and Gas Royalty Regime  
Calgary, Alberta (June 11, 2007) – The Canadian Association of Petroleum Producers (CAPP) and the Small Explorers and Producers Association of Canada (SEPAC) are jointly releasing a new report on Alberta's oil and gas royalty regime. This report, entitled "Alberta's Oil and Gas: Benefits to Alberta and Canada, Today and Tomorrow" provides information on the royalty system in regards to conventional oil and gas and unconventional gas. This is a companion piece to the report on Alberta's oil sands royalty structure previously released by CAPP.

CAPP and SEPAC are pleased to contribute this information to the current public review on Alberta's oil and gas royalties, taxes and fees. It is important that Albertans have confidence in the system – a system that provides fair benefits from the development of natural resources while maintaining an internationally competitive fiscal regime. This is critical to future growth and prosperity. Through the royalty review process, CAPP welcomes the opportunity to share its perspective and listen to those of others.

The report details the current state of resource potential and development in Alberta; the benefits to Alberta and Canada; the costs of operation; and the importance of investment certainty.

- **Resource Potential** – The historical success of Alberta's oil and gas industry has been based on the development of conventional oil and gas. Enhanced recovery technology is being used to extend the life of maturing conventional oil and gas fields. As these resources mature, investment and interest is moving to less conventional resources such as deep gas, coalbed methane, and tight sands and shale gas. These vast unconventional sources are more challenging and costly to produce and require innovative approaches for development.
- **Benefits to Alberta and Canada** – The benefits are more than just royalties, lease sales and taxes. There are new jobs in technical, trades and professional fields, and new business opportunities to provide goods and services from pipelines and equipment to research, trucking, restaurants, environmental and accounting services. All of these contribute to Alberta's economic growth. The challenge for the province of Alberta, as the owner of the resource, is to ensure that this growth continues into the future and that the full scope of benefits continues to be shared fairly.
- **Prices and Costs** – While prices have risen over the past few years so have costs; this trend seems unlikely to change in the short-term. Similar to most commodities, oil and gas prices are unpredictable and rise and fall frequently. Alberta's conventional royalty structure automatically adjusts for price and productivity but it does not adjust for escalating costs. It is important to look at both costs and prices together as it is revenues less costs that drive economic development.
- **Investment** – The existing fiscal regime – with its combination of upfront lease bonuses, production royalties and corporate income taxes – has produced growth, jobs and continuing

benefits for the province. These factors, combined with Canada's political stability and sound fiscal policies, are what make Alberta an attractive place to invest.

The Alberta Royalty Review is examining all of these factors to determine fairness. The current royalty regime needs to be robust enough to accommodate both the maturity and shifting nature of the resource in Alberta. CAPP and SEPAC are providing this information to Albertans to assist in understanding the details and benefits of the conventional fiscal regime. A copy of the report is available at [www.capp.ca](http://www.capp.ca).

The Canadian Association of Petroleum Producers (CAPP) represents 150 companies that explore for, develop and produce natural gas, natural gas liquids, crude oil, oil sands, and elemental sulphur throughout Canada. CAPP member companies produce more than 95 per cent of Canada's natural gas and crude oil.

The Small Explorers and Producers Association of Canada represents "Canada's Oil and Gas Entrepreneurs" with 450 member companies, 80% being oil and gas producers and the rest suppliers of products and services to the upstream petroleum industry. SEPAC's members operate almost 20% of the conventional oil and gas wells drilled each year in Western Canada.

All of the industry presentations can be found at  
[http://www.albertaroyaltyreview.ca/public\\_meetings/transcripts\\_submissions.html](http://www.albertaroyaltyreview.ca/public_meetings/transcripts_submissions.html)

## **Public Opinion and Royalty Rates**

By design, the royalty review was a public process. The 'nuts and bolts' of royalty regime design are, nonetheless, highly technical: the financial levers, the industries' technologies, the geology of the resources, and so on. These different realities need to function together in a stable system and all components need to adapt when changes take place in one or another. Expert presenters, private citizens and organizational representatives, came forward presenting these diverse viewpoints on various aspects of the royalty system and design. The Panel had a wealth of material to consider.

Nevertheless, there is also a 'public opinion' dimension to the process which must be acknowledged and addressed. The views of 'ordinary Albertans' (and many referred to themselves in these terms) were not usually focused on the technical specifics but rather had a broader perspective. There are three independent sources of public opinion reporting Albertans' views on royalty rates. One was presented above from the Panel's website. Another is available courtesy of CAPP and a third from the Pembina Institute. These are discussed below. This section ends with a caution about using public opinion data for issues on which the public lacks clear, current and informative source material.

The Canadian Association of Petroleum Producers (CAPP) report on Ipsos-Reid polling on pages 14 and 15 of their presentation



[http://www.albertaroyaltyreview.ca/public\\_meetings/submissions/2007\\_0522\\_pierre\\_alvarez\\_capp02.pdf](http://www.albertaroyaltyreview.ca/public_meetings/submissions/2007_0522_pierre_alvarez_capp02.pdf)

Ipsos-Reid Question 1

The government actually received 40% of their total yearly revenue from the oil and gas sector for the 2005/2006 fiscal year. This is the equivalent of 14.3 billion dollars. Knowing this do you think the revenues that the government collects from the oil and gas sector are too low, about right, or too high?

Too Low	34%
About Right	48%
Too High	16%
DK/NS	2%

Ipsos-Reid Question 2

Once an oil sands project has recovered its costs and is paying the higher royalty rate, about half of the net revenue generated by the oil sands project is paid to the government in the form of royalties and taxes. Do you think that level of sharing of net revenue is too low, about right, or too high?

Too Low	25%
About Right	57%
Too High	13%
DK/NS	5%

On the first question, CAPP concludes that 64% of respondents think the revenues collected by government are "about right or too high". On the second question, CAPP says the results show 70% think the government take on net oil sands revenue is "about right or too high".

[http://www.albertaroyaltyreview.ca/public\\_meetings/submissions/2007\\_0522\\_pierre\\_alvarez\\_capp01.pdf](http://www.albertaroyaltyreview.ca/public_meetings/submissions/2007_0522_pierre_alvarez_capp01.pdf) (page 5)

Conversely the Panel notes that these results can equally validly be interpreted as indicating something different: that 82% of respondents think the revenues collected by government are "too low, or about right," in general. In the same vein, for the oil sands 82% think it is "too low, or about right" for oil sands.

Taking only the extremes, in CAPP's survey twice as many respondents think the government take is too low as think it is too high.

The Pembina Institute commissioned a study by Probe Research Inc. (reported on the Pembina Institute website <http://www.pembina.org/> )

Question 1: Perceived need for royalty reform

A clear majority of Albertans (61 per cent) support reforming the current oil sands royalty regime so that Albertans obtain a greater proportion of revenues.

**Question 2: A fair share for Albertans**

More than half (56 per cent) of Albertans feel that citizens are not receiving a fair share of the wealth being generated developing the province's oil sands.

**Question 5: Maximizing value for Albertans**

An overwhelming majority of Albertans (90 per cent) believe that the Alberta government should be a leader in maximizing value from the development of non-renewable resources for the people of Alberta.

The Ipsos-Reid and Probe Research Inc. results show the same relationship as the admittedly self-selected submissions to the Panel website. Even leaving keeping the neutral responses in the equation, across all three of these data points one can conclude that public opinion runs in favour of increasing royalties.

Several thoughtful correspondents to the Panel website expressed the view that they had a hard time figuring out how the royalty regime was performing, based on the information available to them.

All of the above simply highlights the profound danger in arguing, at this time, that public opinion should be a basis for redesigning royalty regimes. The information available to the public to determine whether the current system is fair is simply inadequate.

**A Cautionary Note on Public Opinion**

This is a cautionary note that both industry and government need to do a better job of reporting to Albertans. The Panel shared the view, several times expressed to them, that a thoughtful person, expending a reasonable effort, simply could not reach a reasoned judgement as to whether the share was 'fair' or whether the royalty regime was performing adequately. It is important to the ongoing public dialogue on this major sector of the economy that this information gap be filled.

## THE RESOURCE

The design of a fiscal system for Alberta's oil and natural gas resources uses tested and understood design principles with wide application throughout the world. However, these will be tailored to the specific nature of Alberta's resources. There cannot be a 'one size fits all' approach to royalties and taxes such that Alberta could simply copy Norway, Alaska or Texas. The approach in Alberta needs to fit the situation in Alberta. This chapter describes the nature and future of Alberta's energy resources and the royalty regime that has evolved with them. It is background, well known to many, for a discussion of the royalty and tax system's design.

Excellent and extensive documentation on Alberta's energy resources, production, and projections can be found at the Energy and Utilities Board (EUB) web site. This section draws on information and graphics from *ST98: Alberta's Energy Reserves and Supply/Demand Outlook* ISSN 1910-4235. The Canadian Association of Petroleum Producers Statistical Handbook 2007 (linked through <http://www.capp.ca>) is another good source of detailed data about the industry in Alberta and Canada.

### The Energy Sector in Alberta

Alberta's energy reserves are big, second only to Saudi Arabia. The majority of these reserves are found in Alberta's oil sands. The potential production from oil sands is so large many feel it will be a cornerstone of stable supply in a world where political volatility has overtaken many producing regions.

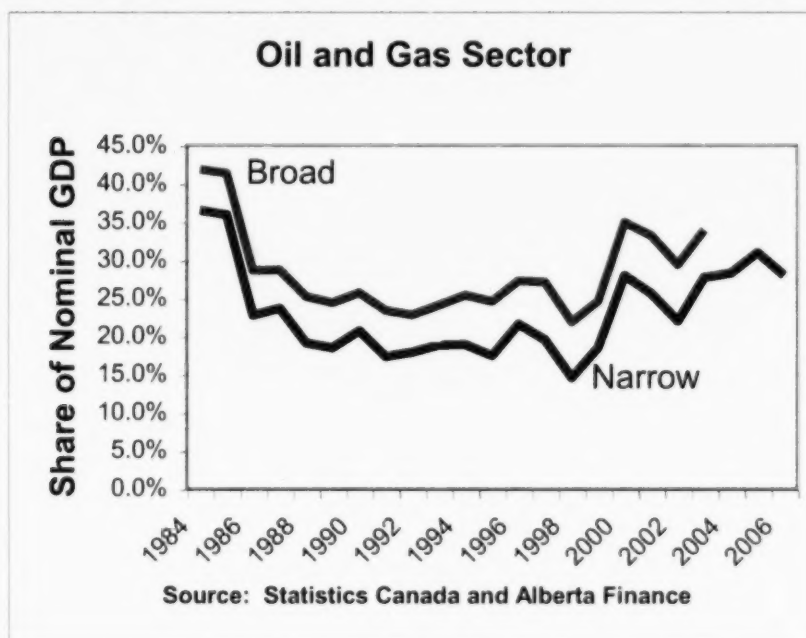
Canada is the world's seventh largest producer of oil and natural gas liquids and the fifteenth largest exporter. [http://www.eia.doe.gov/emeu/cabs/topworldtables1\\_2.htm](http://www.eia.doe.gov/emeu/cabs/topworldtables1_2.htm) Alberta produces 69% of Canada's crude oil. <http://www.neb.gc.ca/clf-nsi/rnrgynfmrtn/sttstc/crdlndptrlmpdct/2006/esccoe06.xls> Canada has the nineteenth largest reserves of natural gas, with 15% of North America's reserves being in Alberta. [http://www.eia.doe.gov/oiaf/ieo/pdf/nat\\_gas.pdf](http://www.eia.doe.gov/oiaf/ieo/pdf/nat_gas.pdf) Twenty percent of the natural gas

produced in North America comes from Alberta

[http://www2.nrcan.gc.ca/es/erb/CMFiles/2005 Review and Outlook English206PFM-02022007-2605.pdf](http://www2.nrcan.gc.ca/es/erb/CMFiles/2005%20Review%20and%20Outlook%20English206PFM-02022007-2605.pdf).

About 30% of the Government of Alberta's total revenue comes from oil and gas royalties, and about one in six Albertans are directly or indirectly employed in the energy sector. By some measures, as much as half Alberta's gross domestic product (GDP) can be linked directly and indirectly to its energy production. Alberta produces 13% of Canada's real GDP. Alberta exports account for about 10% of the oil supply of the United States.

The chart below shows the importance of oil and gas in the Alberta economy. The 'narrow' line includes only oil and gas extraction activities and direct support activities, while the 'broad' line includes related activities like construction, pipelines, transportation and related manufacturing.

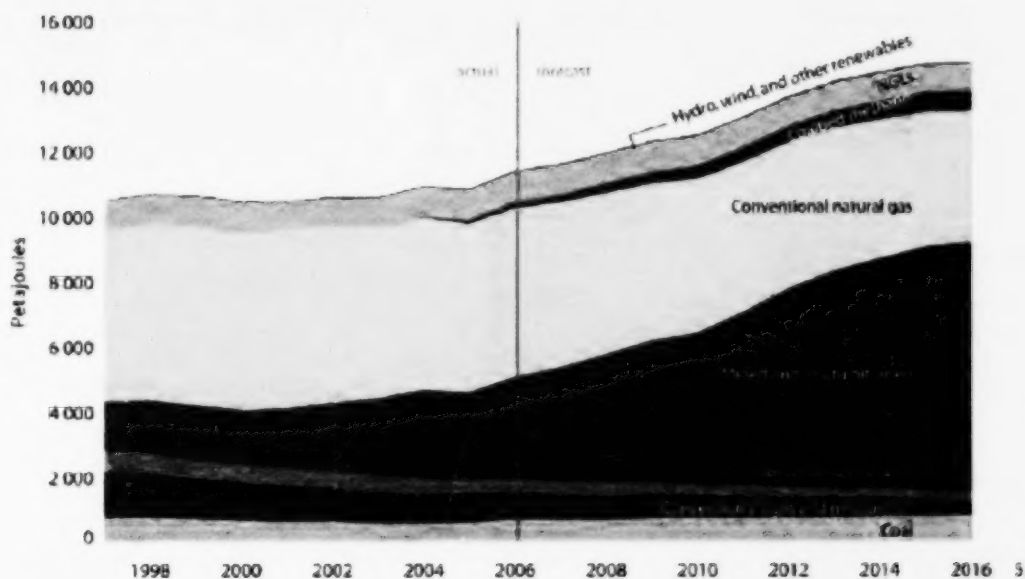


Alberta's energy sector is changing. New discoveries are augmenting established reserves, but the Alberta portion of the Western Sedimentary Basin (the geological formation running along the east side of the Rockies over into Saskatchewan, from the Northwest Territories down into the United States) is mature with respect to conventional oil and gas. This means the discoveries of big new conventional pools or deposits are mostly in the past and conventional reserves are not being replaced as fast as they are being depleted. Alberta is now in a phase where known fields will be

systematically developed, new pools within them drilled, and conventional production of natural gas and oil will continue to decline.

Unconventional production includes bitumen from oil sands and coal bed methane, tight gas and gas from shale. Unconventional production in Alberta, particularly with respect to oil sands, is increasing every year. As the world runs out of inexpensive and easily accessible oil, Alberta really comes to prominence in discussions of future energy production, particularly for the North American market. Bitumen from the Alberta oil sands is not as cheap to produce as the conventional supplies it will replace, but it is plentiful, is located in a politically stable jurisdiction, and has increasingly capable and efficient technologies to extract it and get it to market.

These trends are illustrated in the following charts.



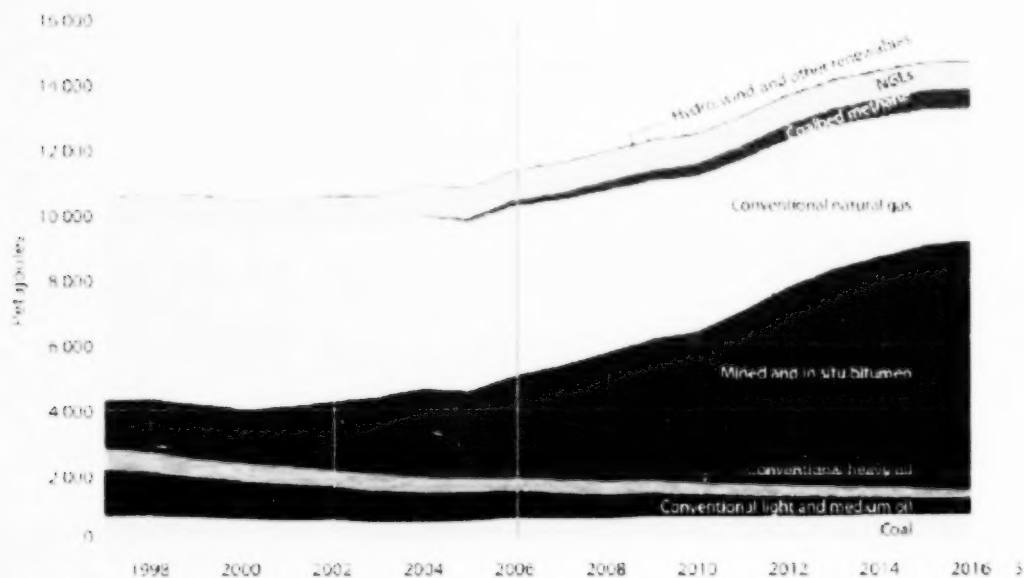
The chart above shows the changing production levels over the years, by resource, and in comparison to each other. Conventional light and medium oil show a steady decline, bitumen a significant increase, and natural gas a slight decline offset by an increase in unconventional coal bed methane (CBM).

The following charts provide information on natural gas and conventional oil reserves in Alberta.

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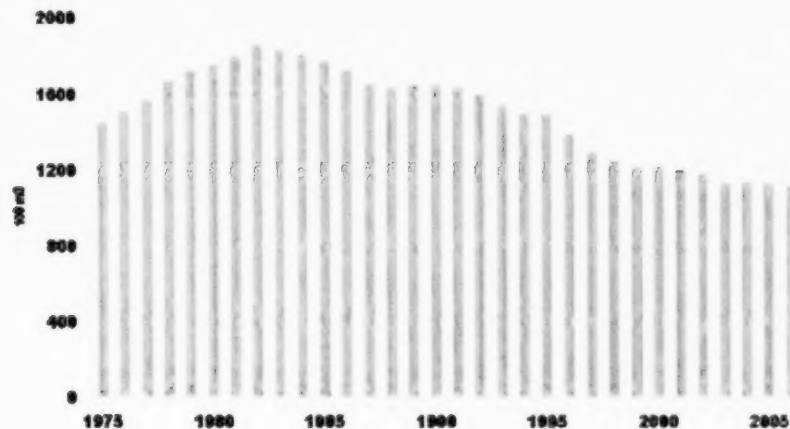
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The charts on this page show the general decline in reserves of conventional crude oil and natural gas.



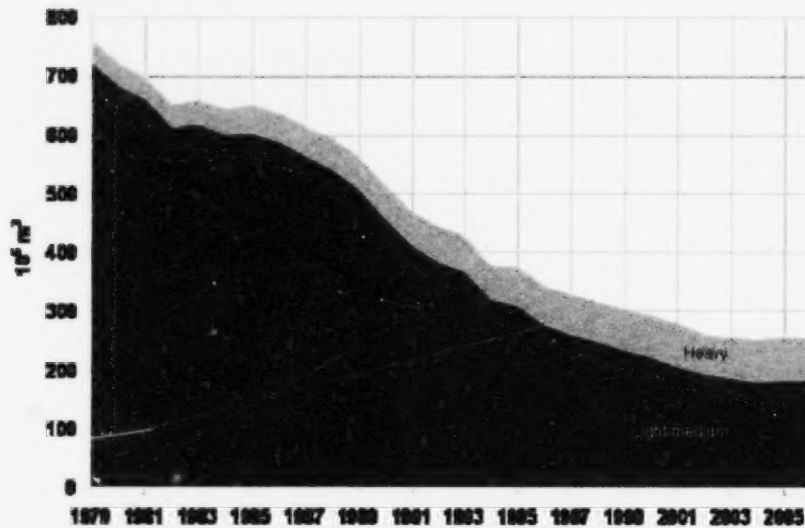
Remaining established reserves of crude oil



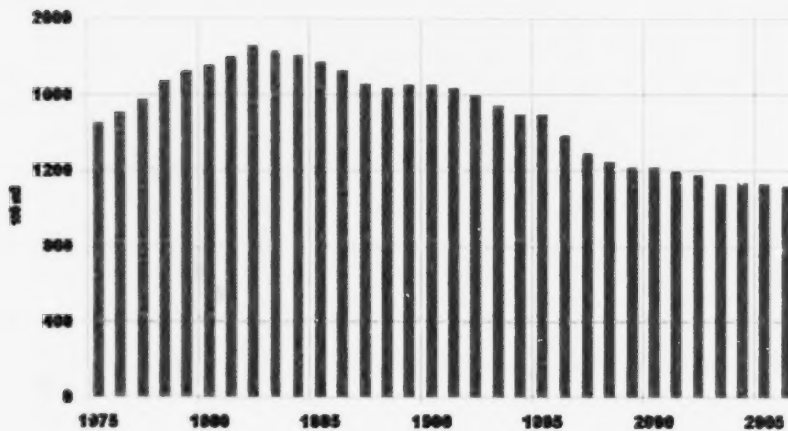
Remaining conventional marketable gas reserves



The charts on this page show the general decline in reserves of conventional crude oil and natural gas.



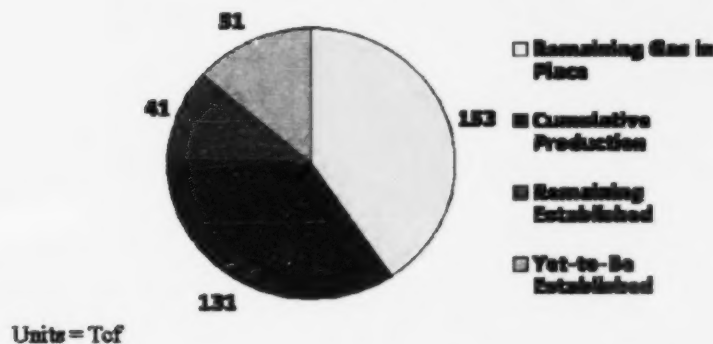
Remaining established reserves of crude oil



Remaining conventional marketable gas reserves

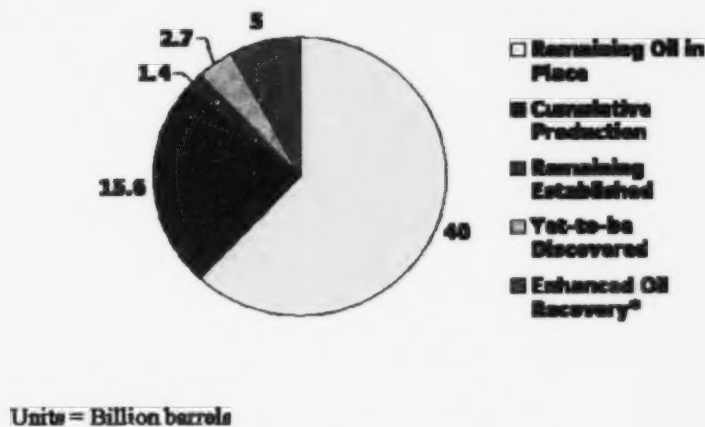
The following charts compare cumulative production to remaining reserves for conventional oil and gas. Remaining gas and oil in place refers to the portions of the resource that are not expected to be recoverable using current technologies under present and anticipated economic conditions.

## Alberta Conventional Natural Gas Basin



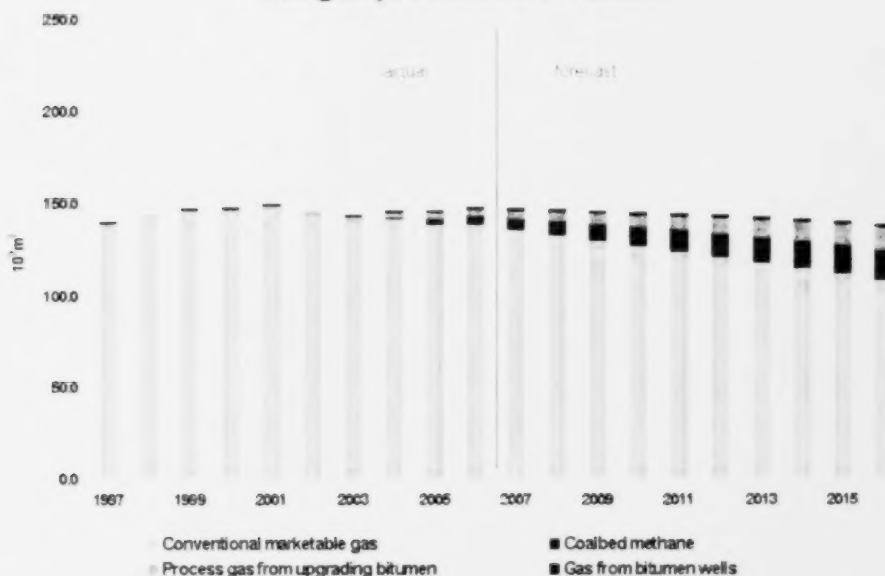
Source: EUB ST98-2007

## Alberta Conventional Oil Basin

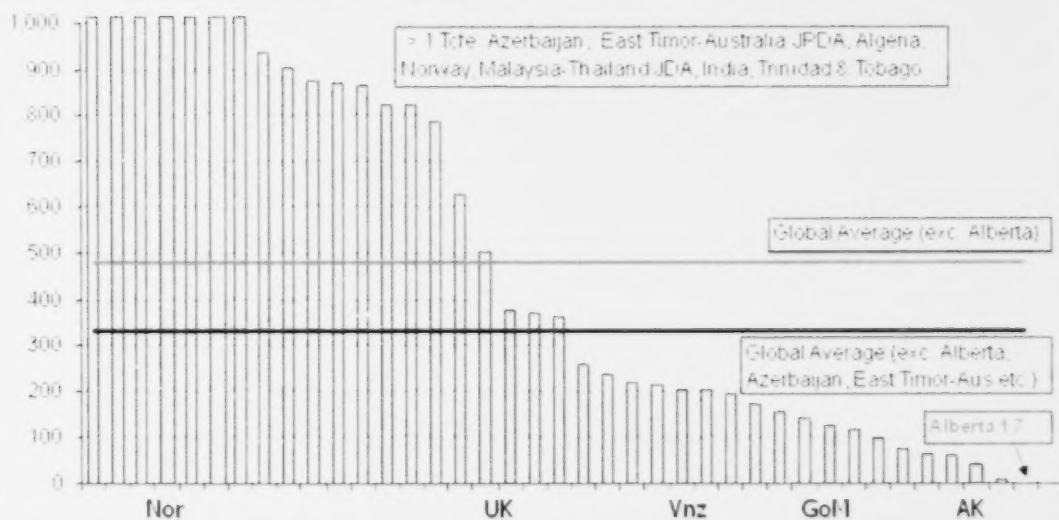


Source: EUB ST98-2007, <sup>a</sup>WTAC Spudding Innovation 2003

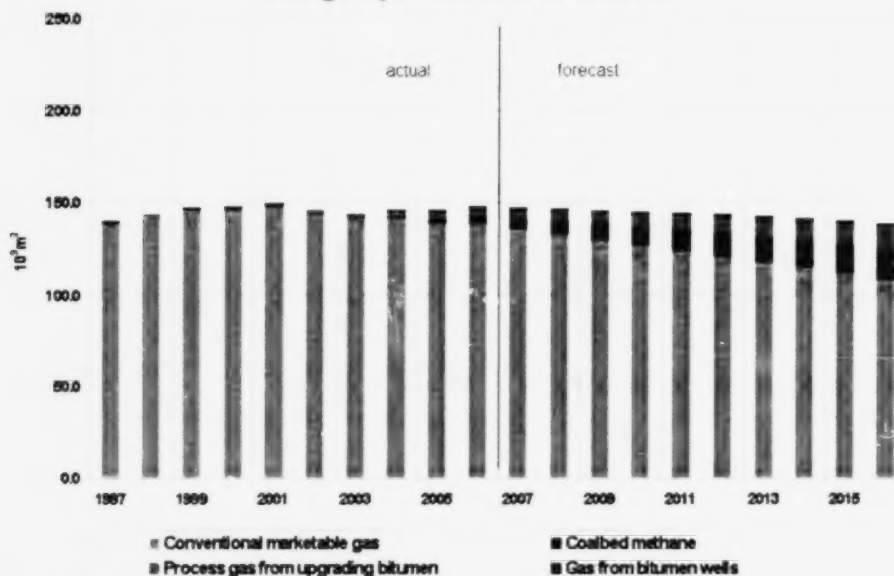
### Total gas production in Alberta



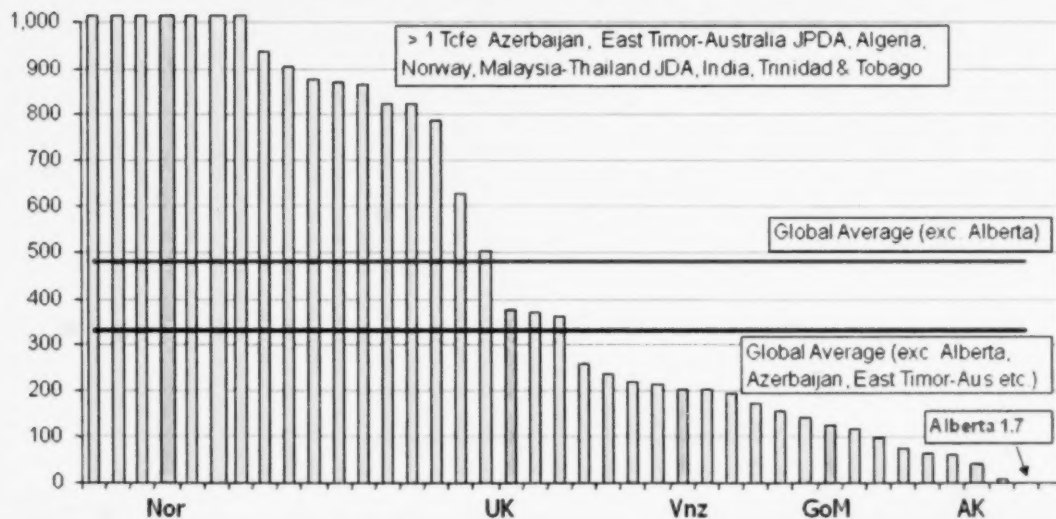
### Average Commercial Gas Discovery Size (bcfe)



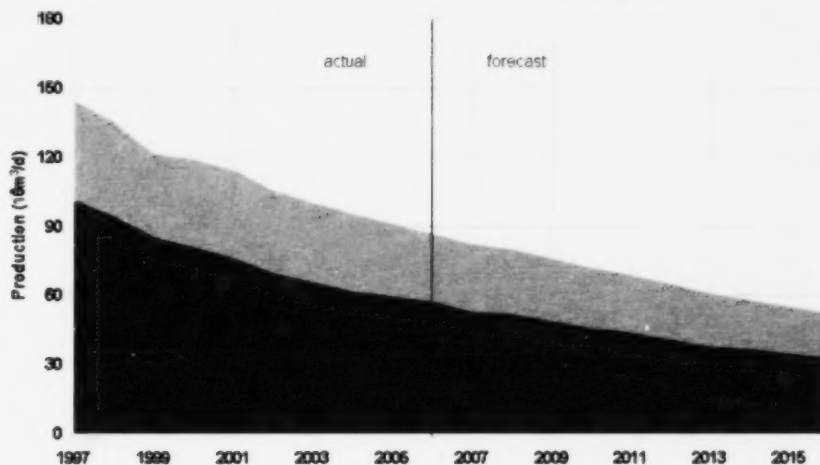
### Total gas production in Alberta



### Average Commercial Gas Discovery Size (bcfe)

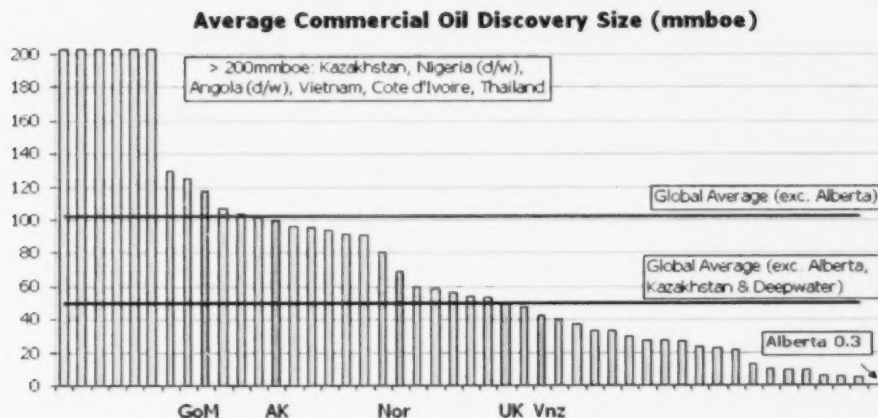


### Alberta daily production of crude oil



The top chart reflects declining production of conventional natural gas. However, Alberta has a huge resource of unconventional gas that is just starting to be tapped. The second chart shows the generally accepted view that conventional oil production in Alberta has peaked and is in decline. This same pattern of declining production is seen in conventional fields around the world.

## Field/Pool Size Oil - 1994-2003



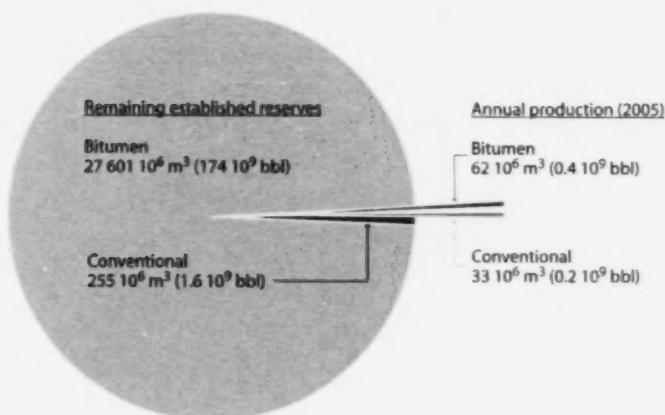
**Alberta has small oil discoveries**

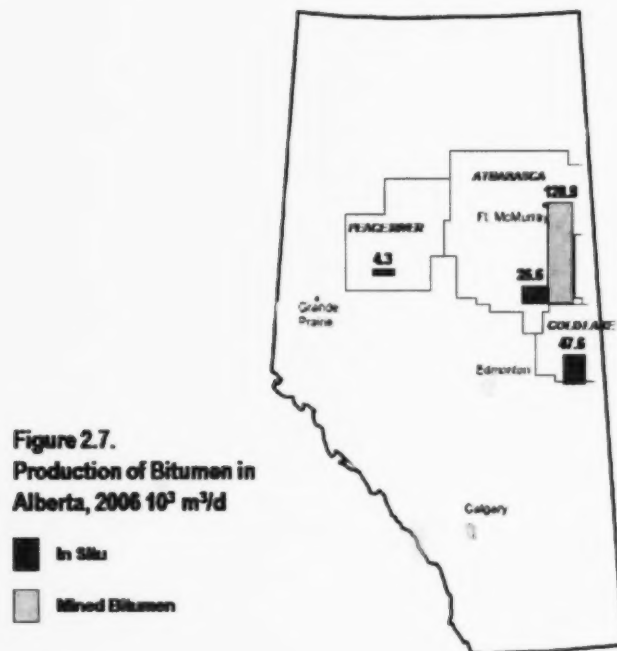
**Established Reserves**

Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.

*CAPP Statistical Handbook*

The chart below shows the overwhelming potential of bitumen, which accounts for 99% of Alberta's remaining established oil reserves.

**Alberta oil reserves**

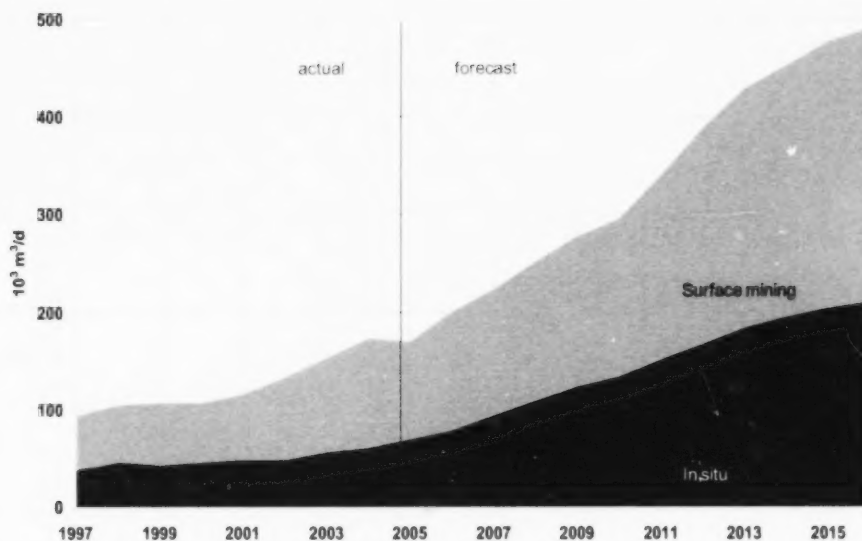


This map illustrates the immense size of Alberta's oil sands reserves in relation to the surface area of the province.

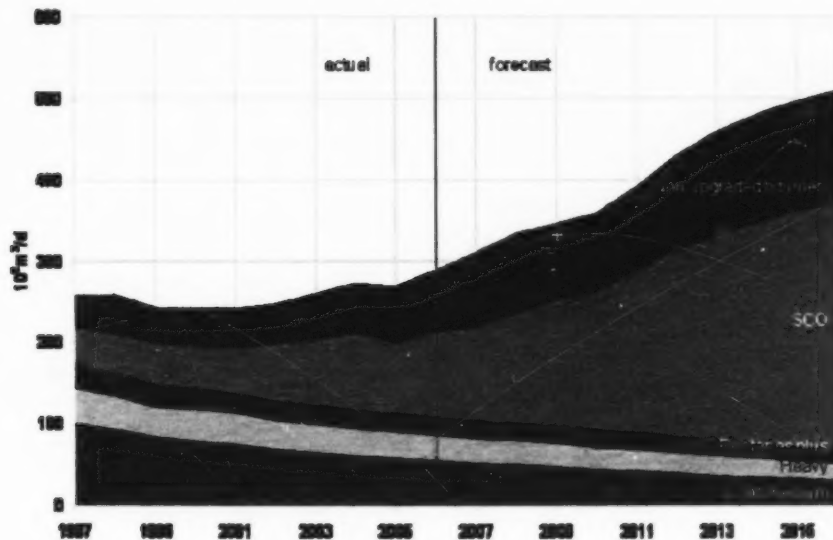
Bitumen production has clearly passed its infancy and production is rapidly on the rise. The following two charts show the increase in bitumen production expected over the next few years.

The chart below compares bitumen production from mining versus in situ.





### Alberta crude bitumen production



Alberta supply of crude oil and equivalent – SCO & Non upgraded Bitumen

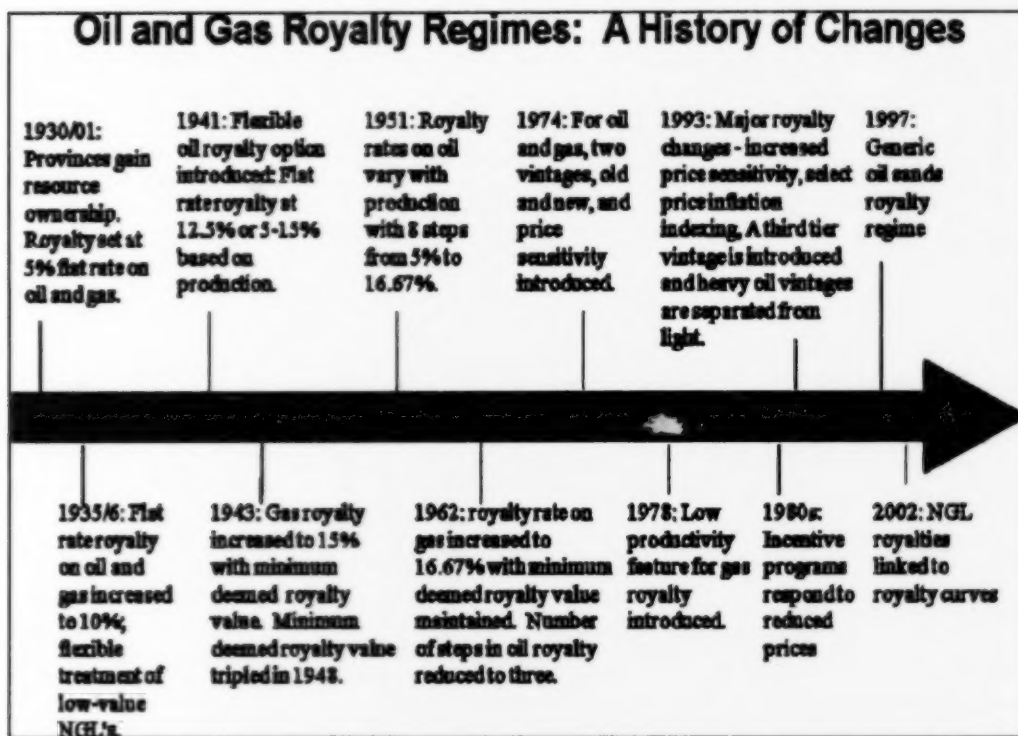
While the decline in conventional production will be more than offset by increasing production of bitumen and upgraded synthetic crude oil, bitumen is a lower valued resource than conventional crude oil. Consequently, the royalties that Alberta can impose on a barrel of bitumen are lower than the royalties that can be imposed on a barrel of conventional oil.

### **How Royalties Work**

While Albertans own the oil and gas reserves located in Alberta, the province does not develop its own resources. Rather, the provincial government grants the right to explore for and develop these resources to the private sector but reserves the right to a portion of the benefits from resource development through the imposition of royalties on the resource producer.

Royalties have undergone periodic revision since the beginnings of the 'oil patch'. The royalty system has evolved over time in response to changes in the discovery and processing of natural resources and other factors such as major shifts in costs and prices. Not unexpectedly, the Panel found editorials dating back to the 1940's warning of the dire consequences of almost every major change, using the same language as the warnings given to this Panel at its meetings.

The chart below gives an historical perspective on the evolution of royalties in Alberta.



How does Alberta's current royalty regime work?

Today's royalty system involves a number of different classifications and categories. Different royalty systems are in place for conventional oil (oil that is pumped from wells located across the province), natural gas, and oil sands. With the exception of the oil sands, royalty rates reflect a combination of the market price of the resource and the productivity of the particular oil or natural gas well.

There also are a number of programs that offset or reduce royalties paid by oil and gas companies. They provide incentives for such things as drilling marginal wells or using carbon dioxide to enhance the recovery of oil from existing wells. A full list of all the various credits and offsets as well as comparisons with other provinces is included in the *Oil and Gas Fiscal Regimes Western Canadian Provinces and Territories* report available from Alberta Department of Energy.

#### Conventional oil

Crude oils are generally differentiated by density, or weight, and how readily they flow. For example, light oil flows easily through wells and pipelines and when refined,

produces a large quantity of transportation fuels such as gasoline, diesel and jet fuel. Heavy oil, by comparison, requires additional pumping or dilution to flow through wells and pipelines. When refined, it produces proportionally more heating oil and a smaller amount of transportation fuels.

Royalty rates for conventional oil depend on a number of factors, including when the oil pool was discovered. Royalty rates for newer pool discoveries, or later vintages, are lower than royalty rates on oil produced from older pools. Over time, the cost per barrel of discovering and developing oil tends to increase because the pools are smaller than those discovered in the 1970s and 1980s. Most of the current oil in production in Alberta was discovered between 1974 and 1992.

The royalty system includes three classifications (vintages) of conventional oil:

- Old oil – discovered before March 31, 1974
- New oil – discovered after March 31, 1974
- Third tier oil – discovered after September 1, 1992.

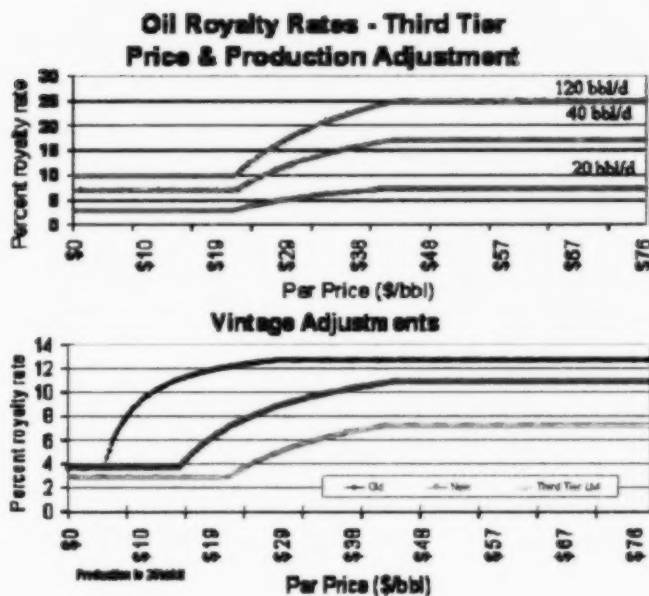
Each oil well is unique, with densities and production levels varying by well. Consequently, the amount of royalties is calculated on each individual oil well, and based on:

- The volume of oil produced from the well.
- The density of oil in the well (whether it is light oil or a heavier oil with a higher density)
- The well classification (based on the vintage of when the oil was discovered)
- A royalty rate factor that reflects the average Alberta market price.

Although the average royalty rate for conventional oil was about 15% in 2005, many wells in the province produce at levels at which lower royalty rates apply. The following example, reflective of a typical well in Alberta, shows the royalty rates applicable to a well producing 20 barrels per day at different vintage levels and compares the royalty rates on that well to rates on wells that produce at higher volumes.

# Royalty Structures Oil

- Average rate of 15% (2005)
- Rates are generally lower for Heavy Oil
- Proportion of production (2005)
  - Old - 26%
  - New - 56%
  - 3<sup>rd</sup> Tier - 18%



These charts show how the royalty rates change for different vintages of oil at different prices. The typical well in Alberta produces 20 barrels of oil per day. The top chart demonstrates the royalty system's productivity adjustment. It shows that wells that produce more, pay more in royalties. Wells that produce less, pay less. The bottom chart shows the royalty curves for different vintage wells producing 20 barrels a day. Above certain prices, the royalty rates remain the same, regardless of increases in price. For example, the royalty rates for a well producing old oil are the same whether the price is \$29 a barrel or \$76 a barrel.

## Natural gas

Natural gas is a mixture of hydrocarbons, mainly methane, in a gaseous state. Water, oil, sulphur, carbon dioxide, nitrogen and other impurities may be mixed with the gas when it comes out of the ground. These impurities are removed before the natural gas is delivered to the end user.

Coalbed methane occurs as a result of the decomposition of organic materials during the coal formation process. Generally produced at lower pressures than conventional natural gas, it requires minimal processing before it is suitable for moving via pipeline.

Coalbed methane and conventional natural gas are subject to the same royalty system. The royalty rate for these products is based on:

- The well classification (based on when the gas was discovered)
- Adjustments for both the average market price of natural gas and the cost of processing the Crown's royalty share of the gas
- The volume of gas produced from the well.

There are two classifications of natural gas: one for old gas discovered before January 1, 1974 and one for new gas discovered after December 31, 1973. About 90% of Alberta's current natural gas production was discovered in 1974 or later.

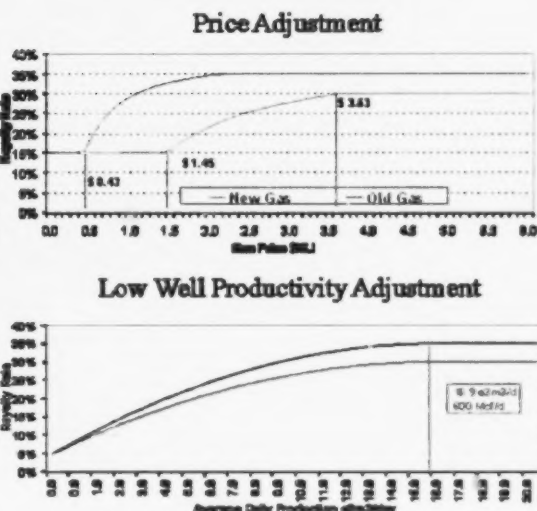
Generally, natural gas royalty rates start at 15% of production and increase to a maximum of 30% for new gas after the price reaches \$3.60 per gigajoule and 35% for old gas when prices are above \$2.20 per gigajoule. An adjustment is made for lower-producing wells. This graduated adjustment can lower royalty rates to 5 %. About 90% of Alberta's wells are considered low productivity wells.

In 2005, the average royalty rate on Alberta's natural gas production was 20%.

Royalties on natural gas byproducts (e.g. ethane, propane, butane, and pentanes plus), are related to the price of the products and can range from 15% to 50%.

## Royalty Structures Gas

- Rates start at 15% and increase to 30% after a price of \$C3.63/GJ
- Rates can be as low as 5% for low productivity wells (< 600 Mcf/d)
- A Credit for Crown's share of processing costs



These charts show how the royalty rates change for different vintages of natural gas at different prices. It is based on a gas well that produces more than 16.9 thousand cubic metres of gas per day. The top chart shows the royalty curves for old and new gas. The bottom chart demonstrates the royalty system's productivity adjustment. Wells that produce more, pay more in royalties. Wells that produce less, pay less. Above certain prices, the royalty rates remain the same, regardless of increases in price. For example, the royalty rates for a well producing new gas are the same whether the price is \$3.60 per gigajoule or \$6 per gigajoule.



### Oil sands

Alberta's oil sands deposits are recognized as the second largest commercial oil deposits in the world, next only to Saudi Arabia. These deposits consist of bitumen, a molasses-like, viscous oil that will not flow unless heated or diluted with lighter hydrocarbons. Technological advances have allowed the economical development of Alberta's oil sands.

Prior to 1997, individual Crown Agreements establishing royalty terms had been separately negotiated with each oil sands project developer. This produced an ad hoc approach that was manageable given the small number of projects in Alberta at the time. However, it did not provide certainty about the royalty treatment for future projects or a level playing field across all projects.

The current (generic) royalty system for Alberta's oil sands was established in 1997 and was specifically designed to encourage the establishment of the oil sands as a viable resource and industry, taking into account some of the barriers faced by oil sands developers.

At that time, the technology for extracting oil from the oil sands was new, the number of companies interested in the oil sands was limited, and there was no certainty that the process was economically viable. Also, costs were high in relation to the oil price - the cost of producing a barrel of oil from oil sands was about \$15 compared to oil prices, at that time in the \$27 per barrel range. Unlike conventional oil and gas projects, with the oil sands, substantial investments of as much as billions of dollars are required to implement a project and it can take several years before oil is produced. These factors were addressed with the introduction of a royalty system that considered both the developers' costs and revenues from the resource.

Under the current generic oil sands royalty system, two royalty rates are set:

- A royalty rate of 1% of the project's gross revenue applies before "payout" - before the developer has made profit equal to the capital and operating costs invested in the project, plus an allowance on those costs equal to the long term government bond interest rate.
- The royalty rate after payout is the greater of:
  - 25% of the project's net revenue (gross revenue minus allowable costs) or
  - 1% of the project's gross revenue.

As of December 2006, there were 66 projects paying royalties under the generic royalty regime. Thirty-two were in the pre-payout stage and 34 were in the post-payout stage.

While at 25% the actual royalty rate is flat, the post-payout royalty regime provides an element of price sensitivity to the extent that profits increase with oil prices.

### What is economic rent?

Economic rent is the difference between the revenues generated by an energy project and the associated exploration, development, and production costs (including a competitive rate of return to the developer). Since economic rent is considered to be a return to ownership of energy resources, the owners of such resources often seek to capture some (or all) of that return by charging royalties on production. Alberta's energy resources generate economic rent because there is a world price for commodities and the cost of bringing those commodities to market is (normally) less than the selling prices, leaving some economic rent for the owner and the producer to share.

Natural resources will not be produced unless their value covers the costs of exploration and development, the fixed and operating costs of production, the costs of bringing the product to market, and a normal rate of return for the investors. This is the total economic cost of producing the energy resources. There are large and systemic differences in these costs, as for example, between conventional oil and oil sands, hence differences in the economic rent available on which to charge royalties.

Royalties to Alberta, and taxes to Alberta and the federal governments equal the total government take. Industry typically looks at total government take to judge the competitiveness of a jurisdiction as a destination for investment. Governments look at the economic rent an energy-production project will generate over its life as a basis to calculate a fair share royalty and government take. If the government take is too high, investment is driven away, if it is too low "rent chasing" brings companies into marginal investments, or "rent dissipation" creates a situation where companies can pay more for everything, so costs go up.

See the Methodology Appendix linked through <http://www.albertaroyaltyreview.ca/> for a detailed discussion of economic rent.

## **NATURAL GAS AND CONVENTIONAL OIL**

The Panel's recommended royalty regime for natural gas and conventional crude oil is intended to create a stable and sustainable framework for the long term. The level of industry activity is an outcome, not an objective of this approach. In and of itself, royalties are not considered an appropriate tool to regulate the pace of development of the sector or the broader provincial economy. However, the royalty regime should recognize the risks and rewards for the owners and developers and be internationally competitive.

Administrative costs and sensitivity to available "economic rent" are key considerations in designing a royalty formula. The major challenge in designing a royalty regime attuned to the economic circumstances of Alberta's natural gas and conventional oil sector lies in the latter's diversity and scope. There are tens of thousands of oil and natural gas wells in the province, ranging from very high to very low daily volumes, and from shallow to deep. They may produce "raw" natural gas that is "wet", "sweet" or "sour"; they may produce oil with qualities ranging along a number of different dimensions, including "heavy" to "light", and "sweet" to "sour". A myriad of factors influence the costs of production for any given well and the value of the products that ensue. Meanwhile, although relatively easy to observe, market prices for the various grades and qualities of products are ever changing.

Applying a pure "rent-based" royalty to natural gas and conventional oil would mean accounting for costs well-by-well, for each of the tens of the thousands of wells in the province. Rather than shouldering the administrative burden of trying to do this, the royalty formulas use the well production level as a proxy for its costs. Highly prolific wells, for example, are able to spread their costs over greater volumes and therefore tend to have lower average costs per unit of production. Low-production wells tend to face higher per unit costs on average.

In examining the royalty regime for natural gas and conventional oil, the Panel considered two fundamental questions:

- Are the current formulas in tune with the evolving resource base and economic environment facing the industry?
- Do they result in a fair share of resource revenues for the owners?

The characteristics of the resource base are described in the previous chapter. In summary, the sector faces:

- Dramatic declines in the average size of new pools being discovered, meaning increasing costs
- Declining conventional oil production
- An increasing share of "heavy" oil production
- In the case of natural gas, reliance on harder-to-tap deposits such as coalbed methane and deep reservoirs
- Challenges to make technological and operational advances to lower costs.

There are two facets to Alberta's conventional royalty system - bonus bids and royalties paid on production.

Bonuses are sometimes referred to as "Signature Bonuses", indicating the payment is made at the time the lease is signed. Leases are purchased from the government at regular sealed-bid auctions; the highest bidder gets the lease. These lump sum payments to the government secure the rights of oil and natural gas producers to explore, develop and produce the resource. The level of bonus bids tends to be highly correlated with the level of oil and natural gas prices. (See Royalty Information Briefing #5 - *Bonuses and Land Rental Fees* <http://www.albertaroyaltyreview.ca/> )

Bonus bids provide the Crown with risk-free revenues regardless of whether or not the oil or natural gas producer subsequently finds a commercial deposit on the lease.

Royalties paid on the production of natural gas and conventional crude oil provide a return to the resource owner once the prospect is developed. When product is sold, the developer (the producer) receives a return on their investment and compensation for the risks they undertook.

### **Where we are now**

The existing royalty formulas were designed to be attuned to the underlying economic conditions facing the producer by being sensitive to prices (known as being "progressive" with price) and the well production rate (as a proxy for well costs). Being price "progressive" means the royalty rate automatically adjusts up and down with price increases and decreases, respectively.

In addition, the existing system applies different royalty rates, depending on the date of discovery of the oil or natural gas pool (its "vintage" or "tier"), on whether the well produces heavy oil, on whether the natural gas well has an especially low production rate and on the chemical composition of the natural gas produced.

Besides the generic royalty formulas and adjustments for vintage and so on, a number of special programs were developed over the years to offset or reduce royalties owing. These programs are discussed in the next section. In general, these are intended to adjust royalties to better reflect the underlying economic circumstances of certain types of resources.

The last major change to conventional royalties was announced in 1992.

All told, the system today is very complex, in part, because the formulas themselves are complex. The various tailorings over the years to adjust for particular resource circumstances or spur different kinds of activity added further layers of complication. Besides the generic formulas, the existing system features:

- Three tiers for oil and two tiers for natural gas
- Low-productivity adjustments for both oil and gas
- Four special programs for oil at the well level
- Four special oil programs at the project level
- Four special programs for natural gas

Today, the majority of new natural gas and conventional oil wells entering production in Alberta qualify for the low productivity allowance (in the case of natural gas), for royalty adjustments through special programs, or both. As the resource base continues to mature and producers' efforts are focussed increasingly on the margin, this will increasingly be the case. "Primary oil" (oil that flows to the well, but is located in the oil sands region) is expected to be a growth area in the future.

## **Key Findings**

### **Bonus Bid System for Natural Gas and Conventional Oil**

The auction system in Alberta functions as intended. There is no evidence of underbidding, lack of competitive bidding or "nuisance" bids. The Forfeiture rule states agreements that are not proven to be capable of producing oil or natural gas expire at the end of their primary term for leases and the end of the intermediate term in the case of a licence. This rule ensures that fallow lands are released in a timely way and discourages speculation.

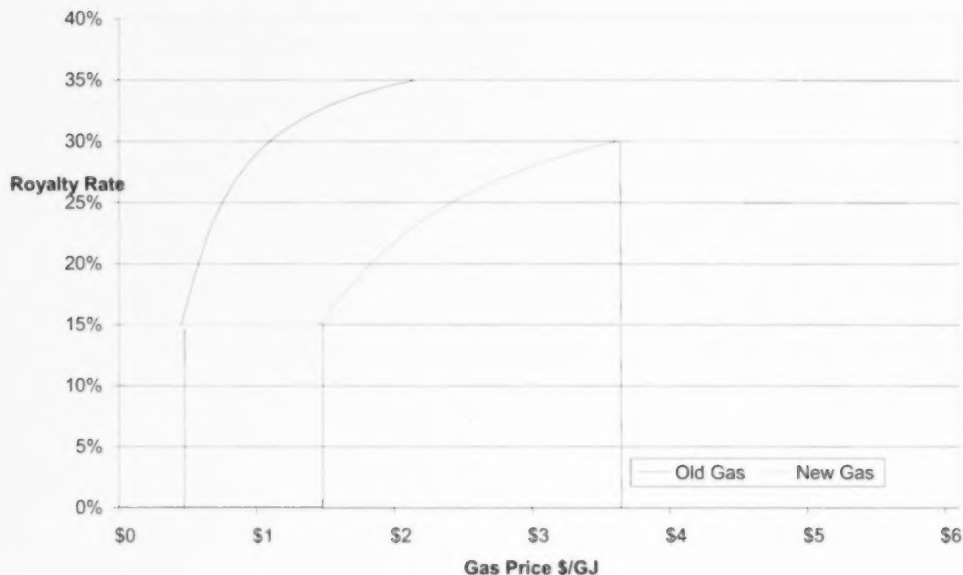
The Panel recommends the minimum bid requirement be eliminated, as the current amount is not meaningful. The government should examine whether the timing of release of parcels minimizes the potential for over-supply.

#### **Royalty Formulas for Conventional Oil**

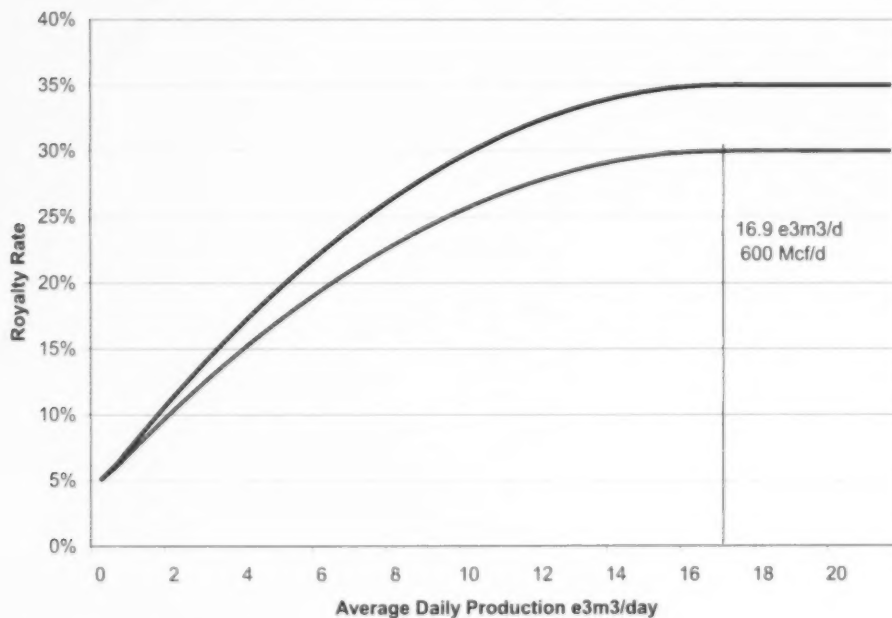
Alberta's current royalty formulas for conventional oil retain some positive features – in particular, sensitivity to the productive capacity of wells. Alberta conventional oil pools are declining in size. This means that, over time, Alberta's conventional resource is becoming more costly to produce (on a per barrel basis). Alberta's royalty system does, and must continue to, account for this evolution in the conventional oil resource base in order to remain competitive. The situation deserves monitoring to assess whether any breakthrough technologies reverse the general trend.

In most other respects, however the royalty formulas for conventional oil are clearly outdated. The Panel has the following general observations and comments regarding the current formulas and their implications.

- The formulas have ceased being price “progressive” at prices well below current market levels. This is the case for all tiers of oil. As a result, the owner's share has not kept pace with price increases.
- More than one-half of Alberta's conventional oil production receives the “new” royalty rate, which is lower than the rate which applies to “old” oil. Under the current royalty system, the proportion of oil subject to lower royalty rates would increase in the future, further reducing the average level of royalties accruing to the resource owner.
- Overall, the Panel finds the current royalty system to be unnecessarily complex. First, the current economics of conventional oil production suggest an opportunity to simplify the royalty system. Second, it is evident that the complexity of the current system substantially reduces its transparency. This means that Albertans do not have a reasonable opportunity to evaluate this system, to determine whether or not they are receiving their “fair share” of conventional oil revenues.



**Natural Gas Royalty Rates Price Sensitivity**



**Natural Gas Royalty Rate Production Sensitivity**



**Royalty Formulas for Natural Gas**

As in the case of conventional oil, Alberta's natural gas pools are declining in average size and productive capacity.

The Panel finds that Alberta's current royalty formulas remain somewhat effective in accounting for this maturation of the resource base, in part, because of the low well productivity adjustments.

Nonetheless, the level of government take on low production-rate wells is found to be too high, in view of the relatively challenging economics for these wells (competitive royalty rates notwithstanding).

The Panel also found that the difference in producer economics on "old" versus "new" wells is relatively slight under current and expected market conditions for low production-rate wells. This finding calls into question the need for a continued distinction between "old" and "new" wells in the royalty formulas, and presents an additional opportunity for simplification of Alberta's royalty system.

**Heavy Oil Production in the Oil Sands Areas**

Under current arrangements, producers of heavy oil in the province's oil sands areas (which are sometimes referred to as "Township 53") are given the option of having royalties on their production assessed according to the regime applicable to conventional heavy oil or according to the oil sands generic regime. That production is classified as "primary production" by the EUB and is not subject to the same challenges facing bitumen production from the oil sands. As a result, even though there is typically more sand extracted as this heavy oil is produced, the production processes used have more in common with those applicable to heavy oil production in the rest of the province than with those associated with bitumen production in the oil sands areas. This finding also appears in the Oil Sands Chapter.

**Special Programs for Natural Gas and Conventional Crude Oil**

Even though the existing royalty formulas are sophisticated and complex, several "fixes" in the form of special programs were necessary over the years to adjust for various resource and production characteristics affecting the level of available "economic rent". Besides a complicated and cumbersome system to administer, the result is that the rate of return from the entire royalty system to the resource owner is not readily apparent.

More detail on the following programs can be obtained from Alberta Department of Energy <http://www.energy.gov.ab.ca/>

Alberta's oil and gas fiscal system includes a number of royalty programs. These programs were developed to address situations where the existing oil or gas royalty regime does not appropriately reflect the unique costs of certain developments or to facilitate special policy direction determined by government.

Generally, these programs encourage the exploration and development of new conventional oil and natural gas reserves, and the conservation and enhanced recovery of existing reserves.

### **Gas Programs**

There are two royalty programs for natural gas.

**Royalty Adjustment Program for Deep Marginal Gas Wells** - This program is designed to provide a lower royalty rate for deeper wells that do not achieve production rates sufficient to compensate for the additional costs incurred in deep drilling. It is scheduled to end August 31, 2012.

**Otherwise Flared Solution Gas Royalty Waiver** - The Alberta Energy and Utilities Board flare management framework established a provincial solution gas flaring volume reduction target from 1996 base levels of 50% for 2002. A royalty waiver is provided to natural gas that is produced from oil wells where it is uneconomic to conserve. The royalty waiver lasts for a maximum of 10 years.

### **Oil Programs**

Conventional oil in Alberta generally has a relatively low recovery factor, approximately 26%, leaving a lot of oil in ground. The oil royalty programs are aimed at finding ways to increase the recovery factor with three main objectives: (1) Increase exploration, (2) Prolong the economic production life of mature pools, and conserve the resource, and (3) Remove barriers to the development of new techniques and technologies that increase efficiencies and promote environmentally responsible development.

The first three programs apply on a well basis, while the last three apply on a project basis.

**Third Tier Exploration Well Royalty Exemption** - This program is aimed at making the economics of the investments needed to discover new pools more attractive.

**Reactivated Well Royalty Exemption** - Generally, the economics of a project will determine when production from a well is terminated. As economic conditions change, reactivating a well may become economic. Bringing these wells back onto production will increase the recovery of the resource.

**Low Productivity Well Royalty Reduction** - As productivity of a well decreases the royalty rate also decreases and costs per unit of production increase. This program is

aimed at encouraging work on wells that can increase the productivity of the low producing wells. The program ends September 1, 2012.

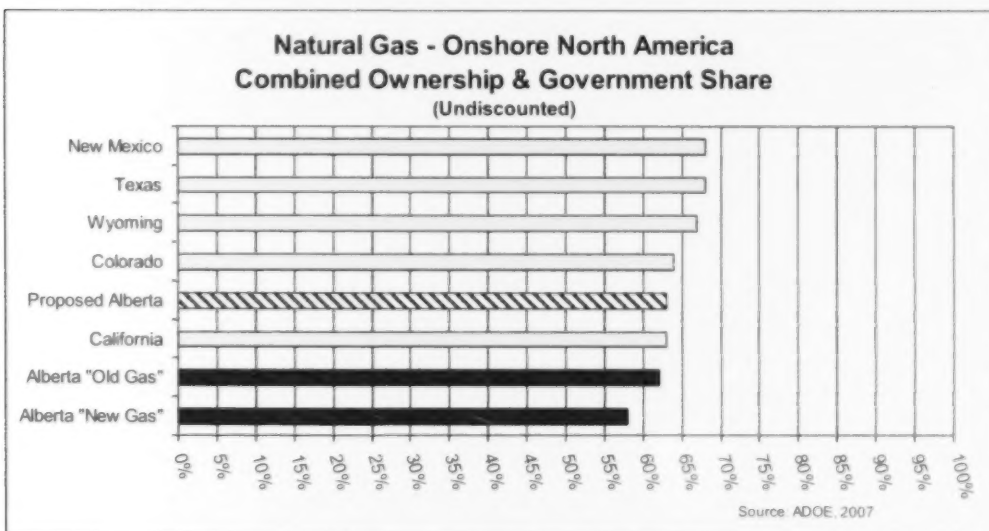
**Enhanced Recovery of Oil Royalty Reduction (EOR)** - Tertiary production (enhanced oil recovery) is a project that uses a substance other than water as an injectant to increase production and is the type of production targeted by this program. The Crown shares in the cost of oil recovery through a reduction in oil royalties on tertiary production.

**Innovative Energy Technologies Program (IETP)** - This program encourages projects that test out new recovery methods in the field. It is scheduled to end June 2009.

**Experimental Project Petroleum Royalty** - Experimental projects will encourage the development of new production techniques, thereby increasing recovery factors. Projects must be approved as experimental by the EUB and receive a royalty rate of 5% as long as they are considered experimental.

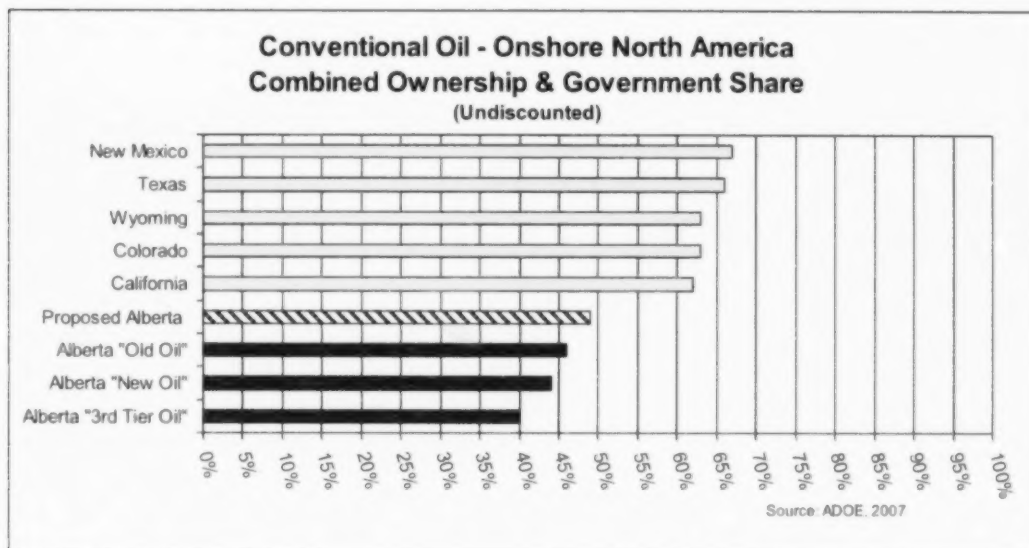
## International Comparisons

The charts below show the current levels of government take in Alberta's natural gas and conventional oil sector, compared to those in other jurisdictions, for given levels of prices and costs. They also show what happens to these rankings if this report's recommendations are accepted.



Represents averages of cases that assume prices of \$US 6 to 8/Mcf and different cost levels. Note

that adjustments were made to account for differences in the location of production relative to markets, as appropriate. See the web appendices linked through for the full report of this analysis <http://www.albertaroyaltyreview.ca/>



Averages of cases that assume prices of \$US 50 to 70/barrel of WTI crude oil and different cost levels. Note that adjustments were made to account for differences in crude oil quality and for differences in the location of production relative to markets, as appropriate. See appendices linked through <http://www.albertaroyaltyreview.ca/> containing fiscal maps showing AB conventional oil and natural gas vs. Texas and the charts showing producer economics (NPVs, IRRs, profit ratios).

On-shore Texas is a particularly good comparison for Alberta because the degree of exploitation and remaining opportunities for producers in the respective producing basins are similar. Comparing Alberta's conventional royalty regime to Norway's or Alaska's – as suggested by some presenters to the panel – is problematic because the resource opportunities – and economics of exploitation and development – are very different.

As shown, the fiscal regimes in Texas and other lower 48 producing states generate very similar results in terms of the level of government and owner take. Whereas the Crown owns most of the mineral rights in Alberta, in Texas – and the other U.S. states of interest – producers negotiate royalties with each private landowner. These are generally a flat percentage of production.

The comparisons show Alberta's royalty regime is considerably more attractive than Texas for low-production rate natural gas and conventional oil wells. (See the fiscal maps in the appendices linked through <http://www.albertaroyaltyreview.ca/>

Because the royalties negotiated between the producer and private landowner in Texas are typically a flat percentage of production, this system is very "regressive" in price and production. It favours high production rate wells and discourages less prolific prospects from being developed. Being much more favourable towards low production rate wells means prospects are drilled under the Alberta regime that would be passed over in Texas.

For very prolific wells, the government take in Alberta is about the same as in Texas.

### METR Analysis

ALBERTA METR	CURRENT	RECOMMENDATION
Conventional Oil and Gas:		
Royalties excluded	6.6	6.6
Royalties included	30.6	42.7

The Panel's recommended changes to the fiscal system for conventional oil and gas will result in an increase in the overall, weighted average, royalty rate. As a result, the royalty inclusive METR on capital will increase for conventional oil and gas, from the current rate of 30.6 percent to 42.7. This remains significantly lower than the 47.3 percent METR in Texas. While it is higher than other sectors, it is justifiable for industries that generate location-specific rents, such as the oil and gas sector, to face higher METRs than other sectors. Under the recommended changes, Alberta's royalty system for conventional oil and gas would continue to be attractive from the perspective of investors.

### Recommendations

The Panel recommends a significant simplification in the royalty regime for natural gas and conventional oil:

- **Tiers** – That the tiers in natural gas and conventional oil that distinguish "vintages" based on discovery date be eliminated. These distinctions no longer serve a useful purpose and complicate administration.
- **Rate caps on price** – That rate caps on price be raised for natural gas to Cdn \$17.50/MMBtu and for conventional oil to Cdn \$120/barrel. The caps are so low that royalty rates are no longer sensitive to market conditions. They do not rise or fall with price changes because prices are consistently above the caps.

- **Programs** – That several special royalty programs be eliminated, since the need for them will be eliminated under the recommended royalty formulas. Several programs are "fixes" to reflect the price and cost insensitivity of the old royalty formulas. This is remedied by the new formulas.
- **Formulas** – That the price-sensitive royalty rate and the volume-sensitive rate become separate elements within a single formula. For each of natural gas and conventional oil, replace the current formulas with the following formula, with sliding rate royalty scales ( $r_p$ ), for  $P$  (price) and  $Q$  (well production), yielding a total royalty rate ( $R$ ):

$$R\% = r_p \% + r_q \%$$

The marginal royalty rate applied to price is  $r_p\%$  and that applied to well production rate is  $r_q\%$ . The maximum total royalty rate payable ( $R\%$ ) for either a natural gas or conventional oil well is 50%. A minimum 2% royalty is payable on natural gas.

- **Use the Natural Gas Reference Price for royalty determination** – That the choice of using Corporate Average Price to determine natural gas royalties be eliminated. Natural gas producers currently can elect to use their Corporate Average Price or the government-determined Reference Price for royalty determinations. The maturation of North American natural gas markets makes this provision no longer necessary.
- **Reclassify existing and future primary oil sands wells as conventional heavy oil wells** – That the option to elect "oil sands" administrative status for primary wells be removed. There are now wells producing conventional heavy oil in "Township 53", an area identified many years ago as "oil sands" for administrative purposes. Producers in this area will no longer be able to elect to have their well administered under the oil sands royalty regime. This recommendation also appears in the Oils Sands recommendations.
- **Gas Cost Allowance** – The Panel recommends that the Crown deem a fee for processing to apply to all gas processing facilities in the province, with adjustments for the different types of plants related to the nature of the gas being produced (e.g., "wet", "dry", and "sweet").
- **Natural Gas Liquids** – That the recommended royalty formula for conventional oil apply to propane, butanes and pentanes plus, regardless of whether or not these products are stripped out of the natural gas. That the recommended royalty formula for natural gas apply to ethane, regardless of whether or not this product is stripped out of the natural gas.
- **Freehold Mineral Tax** – That a flat 6% tax apply regardless of level of production. Retain the base exemption of \$1,600.

The elements of the proposed new royalty formulas for natural gas and conventional oil are shown in the table below. The subsequent figures demonstrate how the formulas



behave with respect to prices and well production rates. Graphs of the natural gas and conventional oil rate curves are available at the Alberta Department of Energy Website.

Conventional Oil and Natural Gas Royalty System				
		Gas	Oil	
<b>Price Component</b>				
Min Rate		n/a	n/a	
Sp <sub>1</sub>		\$3.50/GJ	\$190/m <sup>3</sup>	
	\$/Mcf:\$/boe	\$3.68	30.1923	
<b>Marginal Rate</b>				
PMR#1		2.00%	0.06%	
Sp <sub>2</sub>		\$4.50/GJ	\$250/m <sup>3</sup>	
	\$/Mcf:\$/boe	\$4.73	39.68	
PMR#2		4.00%	0.10%	
Sp <sub>3</sub>		\$7.00/GJ	\$400/m <sup>3</sup>	
	\$/Mcf:\$/boe	\$7.35	63.56	
PMR#3		2.00%	0.05%	
Price Cap Rate		30%	35.00%	
<b>Volume Component</b>				
Min Rate		n/a	n/a	
Sq <sub>1</sub>		2 e3m <sup>3</sup> /d	<=3.5 m <sup>3</sup> /d	
	Mcf/d: bopd	70.60	<= 22.03	
			>3.5 m <sup>3</sup> /d	
			> 22.03	
<b>Marginal Rate (\$/m<sup>3</sup>)</b>				
VMR#1		3.50%	8.00%	
			3.00%	
Sq <sub>2</sub>		5.0 e3m <sup>3</sup> /d	6.5 m <sup>3</sup> /d	
	Mcf/d: bopd	176.50	25.16	
VMR#2		2.50%	2.00%	
Sq <sub>3</sub>		10 e3m <sup>3</sup> /d	10m <sup>3</sup> /d	
	Mcf/d: bopd	353.00	62.93	
VMR#3		1.00%	1.00%	
Volume Cap Rate		30%	30%	
<b>Max Rate</b>		50%	50%	
<b>Minimum Rate</b>		2%	0%	



## OIL SANDS

World deposits of heavy oil and oil sands are as much as 5,000 billion barrels, of which 40% is in Alberta. These deposits have one great advantage over other potential heavy oil developments. They face no exploration risk. In other parts of the world discovery costs may run to several dollars a barrel. In Alberta, we already know where the deposits are.

From every perspective the oil sands are huge: the geographic area, the production potential, the jobs, and the trade-offs between the desirable and undesirable impacts of development. Government policy towards oil sands, in all its dimensions, will be the driving force shaping how we live in Alberta for decades to come. Albertans were "loud and clear" in their presentations to the Panel that they have ideas and want a say in that future.

There are currently two families of technologies used to produce bitumen from the oil sands. For deposits located close to the surface, open-pit mining technologies are used. *In situ* approaches, such as steam-assisted gravity drainage (SAGD), are adopted when deposits are located deeper.

The royalty and tax regime for oil sands projects is a major component of the government's side of the "bargain" with developers and producers to bring bitumen to market. This chapter will propose changes to royalties and taxes, and it will be argued against these changes that they are "breaking the bargain". The bargain was "broken" once before, in the late nineteen nineties. The oil sands sector was new, and undercapitalized. Energy prices were low and the sector was unsure if it had a future. The Governments of Alberta and Canada agreed to change the royalties and taxes then in place to a far less onerous scheme, so that the industry could survive and develop. Industry got the breaks it needed and asked for. Oil sands have since emerged as the dominant factor in Canada's energy future. The breaks given ten years ago are still in place. Just as rebalancing was needed a decade ago, this chapter demonstrates that rebalancing is needed again now.

### Oil Sands Areas

The total "oil sands areas" in the province amount to about 14 million hectares, of that about 45% is currently under agreement. The oil sands "surface mining area" in the province is about 341,000 hectares, more than 90% of which is currently under agreement. (Note: Sometimes, the region in which the oil sands areas are contained is called "Township 53").

Source: ADOE paper "Oil Sands Tenure Background Report"

## Where Are We Now?

The determination of "fair share" for the market environment of 2007 and beyond is not the only challenge facing Albertans as owners of the oil sands resource. The oil sands royalty and tax system also faces two major structural issues: 1) an opaque bitumen market that calls into question whether Alberta's bitumen royalties are based on a fair and competitive market price, and 2) the loose regulation and oversight of costs within its Revenue-minus-Cost (R-C) framework.

These issues, discussed in detail later in this chapter, raise questions as to whether Albertans are receiving a fair share of oil sands revenues. Neither can be fully addressed by simple changes that could be implemented over night. The changes required will need monitoring systems to be built, run, tested and tuned, and then action taken on the output. The other parts of this discussion assume these two major weaknesses will be addressed, because if they are not, other improvements to the system will not rest on solid footings.

## The Evolution of Alberta's Oil Sands Royalty and Tax System

Before 1997, the government negotiated individual "Crown Agreements" separately for each oil sands project. This *ad hoc* approach worked at that period of the resource's development, but as interest grew, more certainty was required for both developers and the government. The cost and time barriers to entry faced by potential oil sands developers required more certainty than could be provided by a series of individual negotiations. The "generic regime" introduced in 1997 met the need. The generic regime is explained in more detail at:

[http://www.albertaroyaltyreview.ca/more\\_info/background.pdf](http://www.albertaroyaltyreview.ca/more_info/background.pdf)

Under the generic oil sands royalty system, two royalty rates are set:

- A base royalty rate of 1% of the project's gross revenue applies before "Payout".

The moment of Payout is not reached until the developer has recovered capital and operating expenditures invested in the project, rentals and base royalty payments, plus an allowance equal to the interest rate on long-term government bonds against the same balance. In general, in determining whether Payout is achieved, the only disallowed expenditures are financing costs and the initial bonus bid (lease) costs.

The concept of Payout is better described, although harder to understand, as the point when a project's "net negative cumulative cash flow" becomes zero.

- The royalty rate after Payout is the greater of:
  - 25% of the project's net revenue (gross revenue minus allowable costs), **or**
  - 1% of the project's gross revenue.

For all practical purposes and for most relevant combinations of prices and costs, this means that after Payout is achieved oil sands companies pay the 25% net revenue royalty, and not the base royalty.

According to ADOE, as of December 2006, there were 66 projects paying royalties under the generic royalty regime. Thirty-two were in the pre-Payout stage and 34 were in the post-Payout stage.

Developers also have the option to choose to pay royalties on bitumen production or on synthetic crude oil (SCO) production. When faced with this choice, developers have opted to pay royalties on bitumen production.

Royalty revenues from oil sands are projected to decrease in coming years due to "...an increased share of oil royalties paid on bitumen rather than on conventional/synthetic crude oil."

(Fiscal Overview: Managing Our Growth.

[http://www.finance.gov.ab.ca/publications/budget/budget2007/fiscal.html#fiscal\\_overview](http://www.finance.gov.ab.ca/publications/budget/budget2007/fiscal.html#fiscal_overview) ).

This is so because an increasing share of oil sands production will be subject to bitumen-based royalties, as developers with Crown Agreements negotiated before 1997 move to paying royalties on their bitumen production in 2009.

At the same time as the generic royalty regime was introduced, the Governments of Alberta and Canada agreed to change their corporate tax systems to extend accelerated depreciation allowances for eligible capital expenditures related to oil sands mining, and upgraders where they formed part of the mining project, to in situ projects. These provisions allow project owners to claim additional capital cost allowances (commonly

referred to as accelerated capital cost allowance) on eligible assets up to the amount of income from the mine. This change put all oil sands players on an equitable footing with respect to their income tax treatment.

## **Key Findings**

### **Albertans Are Not Getting Their "Fair Share" from the Oil Sands**

Albertans do not receive their fair share from energy development, more so from oil sands than from natural gas or conventional oil. The regime for oil sands has not kept pace with changes in the resource base and world energy markets. The total government take from oil sands can be increased while keeping northern Alberta an attractive investment destination.

### **The Revenue-minus-Cost (R-C) System**

With the provisos noted above, the Panel concluded that an (R-C) system is the best way to collect economic rent from the oil sands. From an economics perspective, reference to "pure rent" is the ideal way for the owner and producers to discuss "fair share". The R-C approach provides a relatively simple method of defining pure rent in an environment of changing economic conditions. Oil sands projects, because they are so large and so few (compared to, say, natural gas well drilling) offer one of the few practical situations where an R-C system can be implemented. This assertion assumes that assessment, collection and auditing functions can be brought to bear on companies regarding their royalty payments and that such functions with respect to royalties are at a calibre associated with profits-based corporate income tax collections.

At the same time, however, the Panel believes that Albertans are entitled to share to a greater degree in the "upside potential" associated with higher oil prices. Furthermore, the Panel concludes that this principle should apply both before and after project Payout. An instrument designed to achieve this objective is proposed and discussed later in this chapter.

### **Heavy Oil Production in the Oil Sands Areas**

Under current arrangements, producers of heavy oil in the province's oil sands areas (which are sometimes referred to as "Township 53") are given the option of having royalties on their production assessed according to the regime applicable to conventional heavy oil or according to the oil sands generic regime. That production is classified as "primary production" by the EUB and is not subject to the same challenges facing bitumen production from the oil sands. As a result, even though there is typically

more sand extracted as this heavy oil is produced, the production processes used have more in common with those applicable to heavy oil production in the rest of the province than with those associated with bitumen production in the oil sands areas. This finding also appears in the Natural Gas and Conventional Oil Chapter.

### Costs

During the course of the Royalty Review, the Panel heard from industry that significant cost escalations have rendered the economics of new oil sands investment "marginal". In the context of the oil sands, the Panel has the following observations on the issue of costs.

Cost considerations are already explicitly incorporated in the R-C system. As costs increase, the 1% base royalty is paid for a longer period since the date at which Payout is achieved is delayed.

If cost increases afflict a project that is already in post-Payout, then the 25% net revenue royalties are reduced because higher costs drive one's net revenue lower, all else being equal. Higher costs are also accommodated in the corporate income tax (CIT) for the same reason, resulting in lower CIT payments to both Alberta and the federal government.

Cost increases represent a significant loss to Albertans as resource owners. For a project that is still pre-Payout, cost increases (e.g., project budget over-run amounts) extend the 1% pre-Payout period to allow the company to regain its project cash expenditures in full. As well, if a project is in post-Payout and encounters cost increases, all else held constant, since costs are deductible in the calculation of net revenue royalties, costs increases represent foregone royalty payments to the owner.

Cost control is ultimately a management issue, for which companies must also bear some responsibility.

In addition to materials submitted by Albertans, the resource development companies, and other interested stakeholders, the Panel consulted works by expert consulting firms (such as Cambridge Energy Research Associates and Wood MacKenzie) made available by ADOE. In assembling the cost assumptions used in its assessment of the Panel's proposed royalty and tax system for oil sands, ADOE also benefited from the advice of Pedro van Muiers, an internationally recognized expert in the design and assessment of oil and gas royalty and tax systems.

The Panel recognizes that there is much uncertainty about cost conditions for oil sands projects. The approach adopted by ADOE to assess the Panel's proposals is designed to address that fact by looking at the estimated consequences at a number of different cost levels.

### Credit or Deduction of Base Royalty?

Under the generic royalty system, the 1% base royalty is creditable against the net revenue royalty (currently 25%), since developers have to pay the greater of the two after Payout is achieved, as noted above.

This choice between credit and deduction is important: in the case of a credit (i.e., the current system), the developer pays either the 1% base royalty or the 25% net revenue royalty, whichever is greater in value. With a deduction, the developer pays both the gross royalty and the net royalty, but the gross royalty is allowed as a deductible expense in the calculation of the net revenue royalty.

For example, a project with gross revenues of \$1 billion and operating costs of \$500 million in a given year (after Payout) would pay royalties of \$125 million under a creditable 1% base royalty and a 25% net revenue royalty. This would occur because the project would pay the *greater* of the base royalty – here, 1% of \$1 billion = \$10 million – or the net revenue royalty – here, 25% of (\$1 billion minus \$500 million) = \$125 million. However, royalties would increase to \$132.5 million if the base royalty were made a deduction instead of a credit. In this case, base royalty payments would equal \$10 million – that is, 1% of \$1 billion – and net revenue royalties would be \$122.5 million: 25% of (\$1 billion minus \$500 million minus \$10 million), for a total royalty payment of \$132.5 million. In this simple example, this is a difference of \$7.5 million, or 6%, in royalties paid.

### Bitumen Pricing

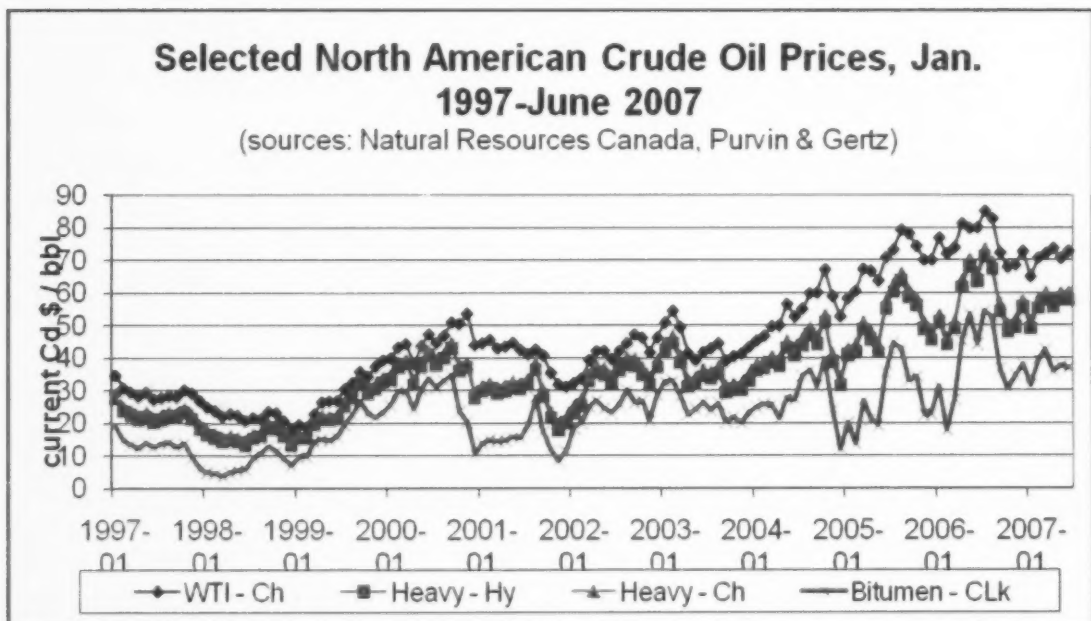
The oil sands produce bitumen. There is no well functioning 'spot market' for bitumen. There is, instead, a thinly traded market with relatively few participants, which is not transparent. Furthermore, some of the buyers are "selling to themselves" through internal transfer arrangements. In these conditions, there is no assurance that observed bitumen prices in Alberta represent the outcome of a fully competitive market. Yet, the lion's share of royalties to Alberta for the next many decades will come from bitumen production for which there is, at the moment, no observable market price. This raises profound questions as to whether Albertans are receiving a fair share for their bitumen resource.

**The situation** - Bitumen will be the primary source of Alberta's royalties in years to come. Bitumen prices are not as high as oil prices and therefore, the royalties they generate are lower. Bitumen has few producers, some of whom are also consumers in terms of their on-site, integrated upgrading facilities. That raises issues around internal transfer payments and an opaque market. Bitumen prices do not show the stability of crude prices. (See the first chart below that shows prices of light and heavy crude oils (WTI and Canadian Heavy, respectively) and bitumen at a number of locations – Chicago, Hardisty, and Cold Lake.) Bitumen prices show an unusual pattern. Since 1997 they

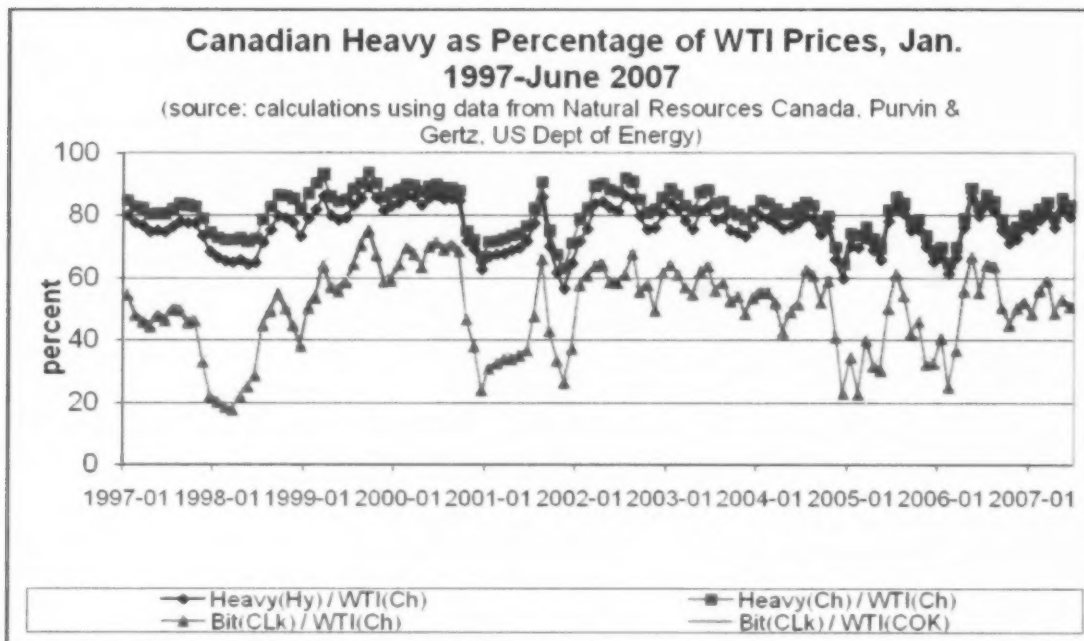


have, at times, spiked down to ~20% of WTI prices, from a mid 50% range, but have not ever spiked up above averages to the same degree. (See the second chart below, which shows prices of heavy crude and bitumen as a percentage of WTI, measured at different locations – Chicago, Hardisty, Cold Lake, and Cushing, Oklahoma.)

**The problem** - In the absence of a transparently competitive market, and/or a bitumen pricing formula, the current state of the bitumen market is a threat to the owner's share. The producers have conflicting interests in the outcome of any negotiated prices – for example, while “stand alone” production operators will seek the highest possible price for bitumen (since this is the end product they sell), integrated miner/upgraders have an interest in lowering the market price of bitumen, because they pay royalties on bitumen but sell upgraded SCO, which does not attract any royalty assessment. When some producers of a commodity are not seeking the highest price, there are good reasons to expect that the market price will be below the “competitive” market price.







### Upgrading

There are different perspectives on how much upgrading of Alberta's bitumen will occur in the province over the long term. While there have been a number of announcements of intentions to construct new upgrading capacity in Alberta in recent months, others have expressed an intent to build capacity in the U.S. Some have expressed fears that Alberta will become primarily an exporter of low value bitumen while the 'value added' to upgrade and refine it will take place primarily outside Alberta. It is impossible to predict the investment choices that will be made in coming years. Major factors in swinging these investment decisions, as we have seen in recent years, have been climbing world energy prices as a 'pro' and rapidly rising costs in Alberta as a 'con'. Press releases from several companies expressing an intent to build upgraders in Alberta total the proposed expenditures at many billion dollars. Whether these projects come to pass, are cancelled or delayed, or are accelerated, will depend on many factors. The Panel observed, however, that periods of large inbound investment might have a correlation with prevailing market prices for oil, and that investment stalls when prices fall.

The construction and long-term economic viability of upgraders in Alberta depends on the availability of labour and material, pipeline capacity, the availability and price of diluent and the demand for bitumen, as opposed to SCO, exchange rates between the Canadian and US dollars, and very likely, the strength and cost of emissions control requirements in various jurisdictions. Alberta's competitors for upgraders are "brown field sites" in the United States (sites of previous industrial activity that can be used to construct upgraders without the difficulties associated with construction on "green field

sites"). There is no doubt that warmer weather and better labour availability give American sites a significant cost advantage over construction in Alberta.

Even if the outcome of 'let the market decide' cannot be predicted, can the market be influenced and should the market be influenced? The Panel looked at the possibility of providing incentives for the construction of additional upgrading capacity in Alberta. Based on available information, the Panel recognizes that incentives for the construction of additional upgrading capacity would be a significant cost to Albertans and may or may not result in the construction of additional upgraders.

Nonetheless, the case can be made that Alberta's future is subject to market power risks if it is only a seller of bitumen, and if it only has the U.S. market for a significant portion of the production. The value-added created by the transformation of bitumen into SCO opens options for Albertans in the future. The case is hard to quantify with today's information as to whether the potential benefits of incenting upgrading exceed the costs of doing so.

This is a question of vision as well as economics, similar to the vision under which Alberta became involved in early oil sands development, including upgrading. Those visionary actions helped create the industry as it is today, but they were not without risk.

#### **Crown Agreements**

The generic royalty formula does not yet apply to Syncrude and Suncor whose output now totals some 49% of Alberta's bitumen production. Their individual Crown Agreements go back to a time prior to when there was 'an oil sands industry' and they were the only two participants. Royalties were then specified as payable on the production of synthetic crude oil (SCO). Modifications negotiated soon after the 1997 introduction of the generic royalty regime gave these two integrated producers the option to choose, as of a certain date, to begin paying royalties on bitumen production instead. The bitumen is far less valuable than the SCO, and therefore the royalties paid will drop substantially as a result. Suncor has already publicly indicated its intention to switch to a bitumen-based royalty in 2009, i.e. it will elect to exercise its Bitumen Royalty Option, known as the "BRO".

Note as well that, for these two developers, the provisions of the current royalty regime (including the rates at which both base and net revenue royalties are to be paid) are enshrined in their Crown Agreements, until the Crown Agreements lapse at the end of 2015. Should proposed changes in the royalty rates be applied to these developers, they might have legal recourse. The financial implications for the developers and for Alberta are significant. In principle, a consistent royalty regime would be preferred, but in practice the cost of changing these agreements must be assessed against the benefits of doing so. That assessment is beyond the scope of the Panel's work.

The share from the Suncor and Syncrude projects has, like other oil sands projects, fallen below the range that would be considered fair. Viewing "fairness" in a broader context, the Crown Agreements are an additional factor which may or may not alter the Government's assessment of "fair share" in the cases of Suncor and Syncrude.

#### **Why a Severance Tax?**

The word "severance" comes from the concept that when the resource (bitumen in this case) is "severed" from its owners (Albertans) a tax is due. Severance taxes are in widespread use in energy producing jurisdictions. Severance taxes are typically imposed at a flat rate, although the rate may be graduated based on production volume or value.

While the Panel supports the principles of the Revenue minus Cost generic royalty scheme in theory, in practice administration and compliance problems associated with R-C systems are evident. Since project costs are a deductible expense in the calculation of Alberta royalties, the province's R-C system is at greater risk of generating inadequate royalties based on reported costs, even if the net royalty is set at a theoretically appropriate rate.

Severance taxes that are sensitive to oil price fulfill two objectives. First, they provide a greater degree of assurance that owners receive fair value for all of their extracted resource. Second, since a severance tax can be price sensitive, it can also be fair to producers because such tuning can approximate a company's "ability to pay." At low oil prices, a severance tax with a low rate will not represent an undue financial burden on companies. On the other hand, as oil prices rise and companies' ability to pay improves, owners benefit from a higher share of oil sands revenues. This approach is both practical and fair.

As a tax of general application, severance taxes apply to every barrel of output produced in a jurisdiction, and to all producers.

#### **Unpriced Inputs**

It is reasonable to anticipate that 'un-priced environmental inputs', for example water, may become subject to more levies and charges from whatever level of government might impose them. Clean air charges are another example, yet to be decided. The Panel notes that these are legitimate costs of doing business and should be treated as such by the royalty and tax system, that is to say as 'deductions' for purposes of the corporate income tax, Payout calculation, and the net revenue royalty, and treated as 'revenues' if some generate income for the developer (for example, a sale of one's water or air emissions permit).

## Grandfathering

The concept of grandfathering has general application for every single recommendation of this Report. However, its impact is greatest for the oil sands, so it is discussed in detail here.

Simply stated, "grandfathering" exempts existing projects from new rules. The concept has potentially broad implication for any changes in the royalty system. If all pre-existing leases and permits are grandfathered under any new rules, then new rules would only apply to new leases and projects. Almost nothing would change. Since the bulk of Alberta's energy leases are already let and the producers now in operation will dominate the market for years to come, there would be very little scope to improve the system. A broad concept of "grandfathering" would preclude the changes of benefit to Albertans, as well as those of benefit to industry.

Some industrial presenters to the Panel made the case that the lease was "an implied contract". Their arguments, in oral questioning, were that all programs and royalty rates in place at the time a lease was issued should be tied to the lease for the life of the lease. This does not have a basis in law or in common practice in Alberta or elsewhere. The rights purchased with the lease do not extend beyond those included in the lease, which are limited to rights of exploration and/or production, and not to programs or royalty rates. Corporations bidding on leases may, or may not, have factored in potential government policy changes. The assumptions companies may have made are an element of their business planning and are often stated in their financial reports.

The reputation of Alberta as "a good place to do business" was frequently raised as a reason royalty rates cannot be changed. In practical terms, this translates to an argument about Alberta's competitiveness. Will investment leave Alberta "on principle" if rates are changed, or will investors continue to monitor the competitive position of Alberta compared to their other investment options? As shown in an earlier chapter, many of the world's producers have raised royalty rates in recent years with little impact on their investment, the extreme case of Venezuela's 2007 changes being an exception. As well, there has been a general trend toward more nationalization under state-owned energy companies or direct state participation in energy exploitation, particularly in large and complex projects. Newfoundland's recent 5% - 10% buy-in deals are a very current Canadian example.

While it may not be 'best practice' for a government to change the rules after projects have begun, it is definitely not 'best practice' for the Government of Alberta to accept something less than a 'fair share', simply because the rules currently in place might have represented a fair share a decade ago under very different conditions. Two valid principles come into conflict because of changes in world energy markets.

## Recommendations

The Panel recommends an integrated package of changes that will increase rates, simplify, standardize, and return the oil sands royalty and tax system to fairness:

- **Rentals** – Under current arrangements, oil sands production leases and licenses that remain undeveloped for periods exceeding 20 years face a schedule of escalating rental payments. The Panel recommends that the existing schedule of escalating rentals begin in the sixth year of any agreement (lease or license) and that no deductions be allowed in the calculation of escalating rentals.
- **Base Royalty** - The Panel is of the opinion that the current base royalty rate of 1% remains appropriate for the “pre-Payout” period, in view of the significant costs of establishing oil sands projects. The low base rate gives producers the assurance that, in the event of a major downturn in oil prices, royalties will not represent an undue financial burden for projects that have not yet recovered their initial investment. The Panel thus recommends that the base royalty rate remain at 1%, but that base royalty payments become a deduction in the calculation of the net revenue royalty. This means that for a project in the post Payout period both the base royalty and the net revenue royalty would be payable (as opposed to the current approach where only the “greater of” the base royalty or the net revenue royalty is payable which, practically speaking, means that the net revenue royalty is what is paid).
- **Net Revenue Royalty** - The Panel believes that the current “post-Payout” net royalty rate of 25% is unnecessarily low, in view of the significant changes that have occurred in world energy markets and royalty/tax systems in many jurisdictions over the past decade. It is the Panel’s view that a net royalty rate of 33% would provide a much fairer return to Albertans as owners of the resource, while at the same time ensuring that Alberta’s royalty system remains internationally competitive under a wide range of market conditions.
- **Corporate Income Tax (CIT) and Accelerated Capital Cost Allowance (ACCA)** - In its 2007 Budget, the federal government announced that it was phasing out the ACCA for oil sands in the federal corporate income tax system.

As part of its mandate, the Panel was asked to examine the *provincial* portion of ACCA.

In the federal budget, the decision to eliminate the federal ACCA was justified on the following grounds:

“This incentive [the ACCA] helped to offset some of the risk associated with early investment in the oil sands and contributed to the development of this strategic

resource. Over time, however, technological developments and changing economic conditions have led to major investments that have moved the sector to a point where the majority of Canada's oil production will soon come from oil sands. As a result, this preferential treatment is no longer required."

The Panel agrees with this assessment. Accordingly, the Panel supports the elimination of the provincial ACCA for oil sands projects.

- **Oil Sands Severance Tax (OSST)** – The Panel strongly recommends that a severance tax as described above, applicable to all oil sands projects, be introduced.

The Panel views the OSST, applying to all Alberta bitumen production, as an absolutely essential component of a "fair" royalty system for Albertans. The Panel recommends:

- That, for each project, an OSST be levied against gross revenues from bitumen production, with a floor applied to the bitumen price equal to 40% of the price of West Texas Intermediate crude ("WTI") in Canadian dollars. This floor price to remain in effect until a permanent, "generic" bitumen valuation methodology is in place, as discussed below;
  - That rentals, base royalty payments, and net revenue royalty payments be deductible from the base against which OSST is applied;
  - That the OSST rate be linked to the price of WTI in Canadian dollars, as follows:
    - Zero for WTI prices of less than \$40/barrel;
    - 1% at \$40/barrel, and growing by 0.1% for each \$1/barrel increase in the price of WTI;
    - Reaches a maximum of 9% at \$120/barrel, and stays at this rate thereafter;
  - That OSST payments not be considered eligible expenditures for purposes of calculating Payout, revenues for royalty purposes, and income for corporate income tax purposes.
- **Project Definition / Ring Fencing** – The Panel did not gain sufficient data to definitively recommend any changes to the current ring fence mechanism under the Generic Regime. However, the Panel very strongly encourages the Government of Alberta to comprehensively and extensively review and tighten, if required, current rules and enforcement procedures to ensure that absolutely clear, transparent, auditable and appropriate definitions exist for projects and eligible expenditures. If this is found not to be the case in practice—if even to a very small extent—then all pertinent rules, regulations and procedures should be improved accordingly and immediately owing to the fundamental role this principle plays in the design of Alberta's oil sands Generic Regime for calculating royalties payable by oil sands companies.



- ***Reclassify existing and future primary oil sands wells as conventional heavy oil wells*** – That the option to elect “oil sands” administrative status for primary wells be removed. There are now wells producing conventional heavy oil in “Township 53”, an area identified many years ago as “oil sands” for administrative purposes. Producers in this area will no longer be able to elect to have their well administered under the oil sands royalty regime. This recommendation also appears in the Natural Gas and Conventional Oil recommendations.
- ***Grandfathering*** – As with all other recommendations in this Report, the Panel makes a recommendation against grandfathering on the grounds of fair treatment for all participants. This issue is treated fully above under the *Key Findings* section.
- ***Bitumen Pricing*** – As noted earlier, there are no well functioning markets for bitumen and the interests of Alberta bitumen producers are not all the same with respect to the price received for their product: production-only developers prefer high bitumen prices, while lower bitumen prices (relative to those for SCO) are in the best interests of integrated producers. “Let the market decide” appears unlikely to resolve this issue in the best interests of Albertans.

For hard-to-price commodities like bitumen, formula-based approaches based on published prices for correlated surrogate commodities are common throughout the world as price-setting mechanisms. The Panel believes the Government’s best option rests with such an approach to pricing bitumen.

A permanent, generic “bitumen valuation methodology” (BVM) applicable to all calculations requiring such a value, used by all participants in the exploitation of Alberta’s bitumen resources where a bitumen price needs to be calculated, should be put in place by 30 June 2008. It would replace all current or intended uses of temporary BVMs and alternatives to the permanent BVM would not be allowed.

In very strong terms, the Panel recommends that a truly independent, unconflicted, world-renowned and highly experienced advisor be hired to consult widely, consider relevant international practices and then develop a permanent BVM. Consultation for this purpose, as a point of clarification, would not entail or imply negotiation nor is it intended to introduce any sense of ‘veto’ power or ‘consent’ requirement on the part of the oil sands industry. As described above, there are simply too many competing interests, too little time left before a BVM is required, and resolving the issue is too fundamental to Alberta’s economy (certainly in the sense of the Treasury of the Province) to continue to leave in limbo or to put at risk of hitting an impasse with industry.

The Panel recommends that the valuation methodology obtained from this process be applied to all bitumen produced in the province for purposes of



determining Payout and for calculating base royalties, net revenue royalties, and OSST payments. Once a permanent BVM is in effect, the bitumen floor price device described above for determining OSST can be lifted, in favour of the new methodology.

- **Expenditures on Environmental Protection and (Currently) Unpriced Inputs** – The Panel recommends that any fees or levies assessed in the future related to the environmental “cost of doing business” for developers and producers be recognized as eligible expenditures for purposes of Payout calculation and in determining net revenue royalties and for purposes of the CIT. Revenues realized as a result of related transactions (such as revenues from the sales of rights, permits, etc.) would be treated as eligible revenues for purposes of determining Payout and calculating net revenue royalties and CIT payments.
- **Upgrader Royalty Credit** – Even though it cannot do so unanimously, the Panel recommends that a tradable royalty credit be introduced at a rate of 5% of eligible capital expenditures on additional upgrading capacity in Alberta for projects whose application to construct and operate an oil sands upgrader is approved by the Energy and Utilities Board (or successor agency) once the bitumen valuation methodology is in place (30 June 2008 as indicated above).

The Panel recommends the following detailed provisions for the proposed upgrader royalty credit:

- The defined purpose of these royalty credits is to encourage the construction of additional upgrading capacity in the province that would not have occurred were it not for the credit;
- It is incumbent on the Government of Alberta to provide the necessary regulatory instruments that would separate, in the case of integrated operations (bitumen production plus upgrading), capital expenditures into those related to bitumen production and those related to upgrading. Capital expenditures related to both bitumen production and upgrading (that is, capital expenditures on physical assets shared between the two functions) are not eligible to earn royalty credits;
- The Panel recommends that qualifying costs for purposes of the upgrader royalty credit be only those costs defined under the *Income Tax Act* (Canada), section 41, and only to the extent that they are directly attributable to new upgrader facilities without allowing for any costs that are shared between, or that are incurred to support, any other types of activity besides the actual process of upgrading bitumen;
- The earned royalty credits can be used to pay royalty obligations by the builder of the additional upgrading capacity or the earned royalty credits can be sold to any bitumen producer in the province (at a price to be determined freely by the buyer and the seller of the credits) which can then use the credits to pay its own royalty obligations;

- Therefore, the builders of additional upgrading capacity can stand to benefit from the availability of the royalty credits as soon as capital expenditures are undertaken and recognized as eligible by the Government of Alberta. (There is no need for SCO production to begin before the builders realize the financial benefits generated by the credits.)

### Assessment and International Comparisons

As part of its assessment of the Panel's recommended royalty and tax regime for oil sands projects, ADOE officials used models maintained by the Department to estimate the "government take" percentage. This is the share of divisible income (total project revenues minus all capital and operating costs) from "typical" oil sands projects accruing to the Governments of Alberta and Canada. Three types of typical projects are considered: a SAGD operation near Cold Lake, a mining-only project in the Athabasca area, and an integrated (mining plus upgrading) production facility located again in the Athabasca area. To facilitate international comparisons, projects typical to a number of comparator jurisdictions around the world were also modelled by ADOE, and estimates of the associated share of government take were derived under each jurisdiction's royalty and tax regimes.

For results over both a select narrow, as well as a broad, range of price and cost conditions—and for more detailed information about the underlying assumptions—please consult the web-resident appendices linked through <http://www.albertaroyaltyreview.ca/> or <http://www.energy.gov.ab.ca/>

The chart below compares the share of (undiscounted) government take for a number of jurisdictions producing heavy oil. This is the best comparison to Alberta's oil sands, and the bitumen in Venezuela would be a very good comparison except for the differences in political systems and philosophy between the two. Note that the estimates for Venezuela are those obtained with the royalty and tax provisions prevailing in 2006, before the recent major policy change implemented in that country. In 2006, international oil companies were still accepting the then-prevailing terms in Venezuela, which are modeled here.

The ADOE results confirm those obtained by van Muers and reported in an earlier chapter: under the current royalty and tax system, the current (2007) share of government take from Alberta oil sands projects is estimated to be "low" (less than 50%), by international standards. The "very low" (emphasis by Van Muers) estimated share of government take associated with the Athabasca integrated project (less than 40%) is linked to the fact that royalties are assumed paid on the bitumen production, and thus that only the corporate income tax applies to upgrading activities.

The chart also shows that, according to the results obtained by the ADOE, the Panel's recommended royalty and tax system would move Alberta closer to the middle of the

pack of the jurisdictions considered, with estimated shares of government take slightly in excess of 60% at \$US 60 oil (and a higher percentage at higher oil prices).

Several factors need to be noted in evaluating these comparisons:

- Alberta's total take has fallen over the years as a result of cuts in corporate income tax.
- Other jurisdictions have enacted policy changes aimed at increasing their take, moving Alberta down the table (i.e. making Alberta much more favourable as a jurisdiction in which to conduct an energy extraction business) since Van Muers' 1997 study. Ironically, Van Muers' now-outdated 1997 study was widely cited by Industry representatives during the Panel's public hearings.
- Oil sands upgrading is a manufacturing process which cannot be shut down without severe re-start costs. A well can be shut in if costs outstrip profits. An oil sands operation would likely continue to operate in an attempt to ride out a storm of low profitability. So operating through price swings has this risk for oil sands owners that is not present in many of the jurisdictions to which Alberta is compared.
- Gulf of Mexico leases are "crown owned" by comparison to the extensive private holding of mineral rights in the United States. An oil importing country such as the USA has little motive to increase its government take to the point that they lose production and have to import yet more oil.
- The United Kingdom North Sea fields are now depleting at a rapid rate, so are a less likely destination for future investment at high total take percentages.
- Alaska, Angola, and Norway are producing higher value crudes under different technical conditions. Total costs to start production, time to production, and production life of a project are all factors that may cause one location to command a higher total take than another.

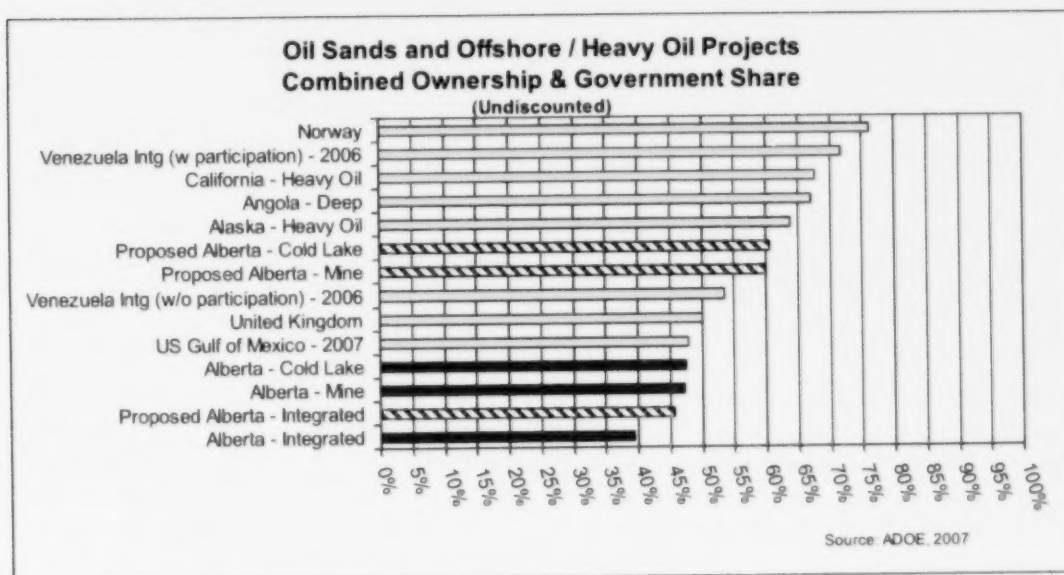
The Panel concludes that its recommendations with respect to the royalty and tax system applicable to oil sands projects would move in the direction of capturing a "fair share" of the benefits from oil sands development for the owners of the resources – Albertans – while also resulting in Alberta remaining a very competitive destination for investments in heavy crude oil/bitumen production.

**METR Analysis**

<b>ALBERTA METR</b>	<b>CURRENT</b>	<b>RECOMMENDATION</b>
<b>Non-integrated Oil Sands:</b>		
Royalties excluded (with ACCA)	3.2	n/a
Royalties excluded (no ACCA)	13.5	13.5
Royalties included (with ACCA)	5	n/a
Royalties included (no ACCA)	16.8	31.8
<b>Integrated Oil Sands:</b>		
Royalties excluded (with ACCA)	3.2	n/a
Royalties excluded (no ACCA)	13.5	13.5
Royalties included (with ACCA)	4	n/a
Royalties included (no ACCA)	14.9	14.1

The recommendations will increase the METR on capital for oil sands operations. For non-integrated projects, the royalty inclusive METR increases from 16.8 percent to 31.8 percent. For integrated operations the METR remains roughly the same, at 14.1 rather than 14.9 percent; this is because of the proposed royalty credit. Moreover, the upgrader portion of integrated operations are not subject to royalties or the OSST.

While the increase in the METR suggests that the recommendations may dampen the incentive to invest in oil sands relative to the current system, the current system was extremely attractive from an investment perspective – even including royalties, oil sands producers faced lower METRs than manufacturing operations in Alberta, which cannot be justified in the presence of location specific rents. Indeed, even after the recommended changes to oil sands, the royalty inclusive METR on oil sands is similar to several other sectors in Canada.



Assumed WTI price of \$US 60/barrel. Note that adjustments were made to account for differences in the crude oil quality and for differences in the location of production relative to markets, as appropriate. See the web appendices linked through <http://www.albertaroyaltyreview.ca/>

## ACCOUNTABILITY

### Statement of Principle

From the very beginning of this review through to the writing of this report, the Royalty Review Panel has approached its responsibilities on the basis of one fundamental premise: that **the energy resources of this province belong to the people of Alberta**. This bedrock principle has informed and guided each and every one of our recommendations.

This principle also has implications which reach far beyond the specific recommendations of this report that relate to royalty and tax rates. It also implies, and indeed demands, actions on the part of the various stakeholders who either affect, or are affected by, energy development in this province. This includes Albertans as owners of the resource, the government as 'agent' for the owners, and industry in its role as the developer of the owners' resource.

In this report, we have emphasized that the government is simply an 'agent' for the **true** resource owner – **Albertans**. The term 'agent' is in some respects insufficient, in that the government is also acting on behalf of future generations of Albertans who are not presently in a position to advocate for, or otherwise protect, their interests as the inheritors of Alberta's resource bounty.

The government of Alberta is, in effect, the **trustee** for the resource owners - both current and future. As such, it must also meet the highest standards of performance that accompany the role of trustee. Further, if it fails to meet these standards, it must be held accountable. However, the only way that true accountability can be achieved is if all stakeholders have access to the information needed to assess standards of performance. Without such information, "accountability" is a hollow and lifeless concept.

It is in this spirit, and with this understanding, that the Panel offers the following assessment of the current state of accountability in Alberta's energy royalty regime. The



Panel goes on to take this opportunity to make recommendations to address the serious "accountability gaps" which it discovered in the course of its review.

### **The Panel's Findings**

In the case of collecting "fair share" from Alberta's energy harvest, it is not the thought that counts. A plan to collect money depends on execution, and the value of good intentions depends on outcomes. Someone has to be accountable for monitoring operations and taking corrective action if intended results are not achieved.

The Panel is unanimous in declaring that Albertans do not presently enjoy a transparent and readily-evaluated royalty regime for oil and gas. This finding by the Panel lies in two realms:

- The government's performance as trustee for the resource owner -Albertans , and
- Industry compliance with the intent of the fiscal regime, with particular reference to the "Revenue minus Cost" royalty system for oil sands.

Both of these facets of the workings of Alberta's energy industry seem shrouded, without an accusation on the part of the Panel that this result is intentional.

In a "first world" jurisdiction in the 21<sup>st</sup> Century, nothing less than full disclosure of all aspects of a public, multi-billion dollar enterprise which develops the owner's resource is the entitlement of every single citizen. Albertans should expect at least as much reporting and analysis about the returns and risks in their collective energy portfolio as an average investor or shareholder can expect from an average broker or management team regarding their investment portfolio. In the case of Alberta's multi-billion dollar energy reserves, seen as an enterprise, the onus on government to inform the public should actually be orders of magnitude higher. Stated politely, this standard of disclosure is not presently being met.

Inadequate disclosure is, in part, the natural outcome of an increasingly complex and multi-faceted Alberta energy industry, coupled with an inability on the part of government to "keep up" with developments. The Panel is of the opinion that the government has not built up sufficient expertise and capacity to administer and manage this complexity. Further, available expertise and capacity is allocated in a manner that does not provide the most efficient and effective use of government resources. Finally, the basic corporate objectives of certain government organizations appear to be in conflict with one another, to the apparent detriment of Albertans as resource owners. These observations lead the Panel to the conclusion that fundamental reforms are needed.

Many straightforward questions put to the Department of Energy by the Panel were not met with answers. The lack of answers was not a question of an unwillingness to answer by the Secretariat directly supporting the Panel. In fact, the Panel and the Secretariat



were given extremely strong support from the very highest levels of the government and remarkably total independence from all levels of the government to make sure the Panel's work was unencumbered and free of influence.

Rather, it seems that the Department of Energy bureaucracy might have been caught "flat-footed" by the Panel's enquiries because useful information is not adequately collected in the first place. Sometimes, it was a matter of being unable to extract basic information from the present systems with the present staff. These issues were most acute with respect to the oil sands. How the administration or public leaders make informed decisions in this vital arena is an open question. Alberta's production levels will soon rival the production levels of the Top 10 or Top 5 OPEC producers. Without changes to the management approach toward this province's resource, that "management" will be undertaken without adequate, actionable, reliable data.

Failing to collect the fair share of Albertans' royalties because of overly-accommodative rules and under-funded administration is a false economy. At 20-40% of provincial government income, and especially because the resource belongs to Albertans in the first place, the royalty system should arguably be far more "tight" and transparent than the corporate income tax system, and it definitely is not.

As resource owners, Albertans have every right to information about how, and for what prices, their resources are being disposed of, to the fullest extent that is also consistent with the legal/privacy rights of corporate entities who develop Albertans' resources under lease. To cite one example where this information is clearly lacking, consider the oil sands and its R-C (Revenue minus Cost) royalty regime. Because reported costs in this royalty system have a direct impact on how much Alberta receives in oil sands royalties, Albertans need and deserve much more information on how costs are accounted for, and verified, in this system. The Panel itself, even after exhaustive study, was left with many questions and concerns in this regard.

We cannot know what an adequate information system would have reported for years past. That data and those insights are now lost to the owners of the resources. It would have been interesting, for example, to know how it comes to pass that the NOSTF recommendations for oil sands were accepted at a level of total government take around 60-63% and the actual take generated by the tax and royalty system today is closer to 47%. It is not as if world oil prices increased from the 'teens and low 20's of dollars per barrel only just this year nor, even, did price levels only start rising in 2006. With a difference between original intentions and actual outcomes as big as 13-16 whole percentage points, is the decline in government take the result of policy, of implementation, of compliance, or of auditing? Was it a decision not to implement mid-course corrections, or a failure to notice the drift off-course? Imagine the repercussions if the income tax system experienced such drift and nobody knew or nobody seemed to give "a tinker's damn".

On another basis, it appeared very late in our work that oil sands remittances might be victims to a "broken ring fence" mechanism under the R-C regime, or facing some other

issue, given what preliminarily seems like a pattern of material deferral of payments that is not in the interest of Albertans. In clear language, it seems that achievement of expected, intended royalty collections falls short of the actual amounts collected. Keep in mind, however, that the work that was possible in this regard was plagued with all of the above issues of inadequacy of records and prior period analysis. These findings were relayed to the Panel on August 24, 2007, by Dr. Pedro van Meurs, a world-renowned expert in energy fiscal systems and there has not been adequate opportunity to delve further into this inconclusive finding. To say the least, admittedly-preliminary, draft findings such as these left the Panel troubled on the question of whether Albertans would be receiving their "fair share" from oil sands royalties even if its policy recommendations are adopted in their entirety.

The problems are complex and require action on a number of fronts. The first step involves simplifying and modernizing the royalty structure, eliminating "patches on patches" used to shore up an ever-more out of date system, and introducing drastically less complex royalty mechanisms: the Panel has made all such recommendations earlier in this report, and it has done so on a balanced basis across all the commodity sectors.

The second step involves an accountability mechanism and culture. This latter step will require profound changes in both government practices and citizen engagement, as well as cooperation from industry.

Accountability and transparency--both in terms of energy companies operating in Alberta's fields and in terms of the government itself relative to its citizens--are the key to assuring that the government attains the intended collection of dollars at any level of established royalty and tax rates.

## Recommendations

### Accountability Across the Board: Government, Industry and Citizens

*As agent/trustee for the resource owners, the Alberta Government's role is to collect the "economic rent" associated with the resources (note: the Panel's mandate did not include the coal resource). In practice, this means setting appropriate taxes and royalties, maintaining their relevance over time, and collecting them efficiently. The government is accountable to the citizens of Alberta in fulfilling these duties.*

In the spirit of ensuring that the proposed new royalty structure (or any other regime) lives up to its objectives, the Panel makes the following recommendation in the strongest possible terms: The government of Alberta must implement means to gather and assess the workings of all aspects of revenue policy and collection associated with energy resources in the province. This must be done on behalf of the citizens of Alberta, and its findings must be made public and have the highest degree of credibility. **It must not** be a confidential exercise internal to the government.

The Panel envisions a function and culture similar to that of the Auditor General. In some jurisdictions, a "Super Ministry" or a Deputy leader is primarily tasked with oversight for large, critical and strategic areas like this one that span many aspects of the economy and social realm. Whatever form such a body might take, if the government creates this kind of capability in-house, the funding for this activity would need to be non-contingent (e.g. not subject to political, lobbyist, or other influences) and not trivial as to amount.

Having seen all the competing interests that have a stake in Alberta's energy sector, and the different Ministries that bear directly or indirectly on the revenue that the government can collect from this sector, the Panel feels that the envisioned function would only be effective if it reported directly to the Premier. The work would be published to the Legislature and this would be done as frequently as any multi-billion dollar corporation (e.g. quarterly interim reports with annual master reports). Issues and areas that would be covered by the public reports would include this non-exhaustive list:

- Achievement of targets (e.g. targeted Government Take %)
- A ranking of Alberta's Government Take % relative to that of all other comparable jurisdictions
- An asset catalogue for tracking announcements, construction starts and operational start ups
- Regular reports on costs, materials, labour and seasonal aspects of development
- Information on the impacts of various energy policies (e.g. Upgrader Royalty Credit), both as an expense and as an incremental in-flow.
- Any and all "side deals" and special arrangements or incentives, brought forward to the House for evaluation prior to implementation
- Audit for unintended Royalty leakage in the ordinary course of companies' operations.

The people, institutions and contractors involved in these efforts must be empowered at the highest available level to interact with all Ministries in the government, and also with any and all aspects of the energy companies themselves, again with the same authority levels as the Auditor General.

Standards of compensation and performance of parties involved with this effort would need to be world-class. Notably, given the inherent necessity to constantly be attuned to international standards and common practices regarding royalties, taxes and lease terms in far-flung regions of the world, it would be essential that skill sets of a sufficient depth and number be present in the organization or set of organizations which are discharging this duty.

Capabilities and skill sets needed to staff this function would be very wide-ranging and would need to be extremely senior, preferably with deep prior industry background across all three sectors (natural gas, oil sands and conventional oil). Like a business,

critical skill sets to analyze, develop and implement are required to cover off all aspects of exploration, development, operations, and energy sales & marketing. This would include actual operations knowledge and hands-on experience, from geology and prospecting through to refining & transport/pipelines, along with everything in-between.

The use of retired individuals would be advisable, as they will not be threatened or compromised vis-à-vis future industry employment. On the administration/filing side of the equation, skill sets would include legal, accounting, audit (including forensic auditing), and familiarity with tax and royalty calculations and associated filing. As well, statisticians and actuaries would be highly useful, and it would be remiss to not have strong capability to depict complex data and ideas in graphical form. Familiarity with other energy-related legislation and regulation would also be helpful, in the Panel's opinion, and so expertise in the Environmental realm and Municipal taxation would also be an asset.

Given that being internationally competitive with other jurisdictions is one of the cornerstones used to assess fairness, Albertans will need to know how their fiscal regime compares with far-flung, relevant foreign countries. Those countries' legislation, bureaucrats, industry executives, reference materials and public accounts will all need to be consulted. The preceding point would entail not only working across multiple time zones, but also international travel that might be expected in order to perform an on-going assessment of Alberta's ranking of its Government Take % against that of other jurisdictions. All of this makes it self-evident that a deep and complete fluency in various relevant, and sometimes obscure, languages would also increase the effectiveness of this new element of government- and developer-accountability.

As mentioned above, the new independent oversight being suggested by the Panel would be expensive. However, the lack of having such a capability has had consequences that, in the Panel's view, have been very costly along several dimensions. Given the stakes for current and future generations of Albertans, and given the desire to make the outcomes fair on an on-going basis to affected parties (the resource owner and its agent – the government, and energy companies), the collective effect of the recommendations in this section represent a very substantial and costly effort. However, as large as this investment might appear in isolation, it would be a tiny percentage of the value at risk. It would also be more in keeping with the execution of multi-billion dollar fiduciary duties in a typical Western nation.

The Panel believes that investment in this new oversight capability would pay for itself many times over. It will also help to strengthen and sustain citizens' confidence in the system, which the Panel saw called into question many times during the course of its review.

Next, the Panel reaches a difficult recommendation that, while directly applicable to its mandate, may be seen as a betrayal of a department with which it has had to work very

closely for the past six months. It is this: Alberta must conceive a go-forward environment for royalty design, maintenance, fairness and effectiveness that is not inherently conflicted in the hands of its functionaries. One seemingly simple, and also obvious, problem that occurred to the Panel throughout its work was that the Alberta Department of Energy is tasked with Mission Impossible. One cannot, by definition, be **simultaneously** responsible for **both** maximizing activity in the energy sector (in terms of rule-setting, licensing policy, etc.) **and also** ensuring that Albertans receive their "fair share" from energy development in terms of royalty terms-design, and audit/policing of royalty compliance. Those two mandates work in opposing directions and tradeoffs against this and other sectors of the economy also come into play. During the public hearing process, the Panel heard many submissions about competing interests relative to the Energy sector.

Related to this point, the government must restructure and redeploy authority and procedures to ensure that spending decisions by the Alberta Department of Energy receive at least as much legislative or Treasury Board scrutiny as spending decisions by any other Ministry. In this context, the Minister of Energy is judge, jury and executioner when it comes to creating special incentive programs or royalty holidays that defer, reduce or eliminate income for the Province. By the same token, his or her department also designs and deploys the royalty programs. This juxtaposition of both regulatory and implementation responsibilities in Energy is different than Norway's approach, for example.

Apart from any required changes to existing Ministries, the Panel acknowledges there may be several ways to source and deploy the resources that could execute some of the government and industry oversight, effectiveness assessment, auditing & public reporting roles envisioned above:

- A sister organization to the Auditor General, but with the above characteristics and mandate, and/or
- A system of two independent, rotating oversight firms similar to that to which Schedule 1 banks must submit, and/or
- Some other international calibre, independent and un-conflicted entity that has deep industry expertise in all the required disciplines, and/or
- A Super Ministry for Non-renewable Resources.

The Panel strongly believes that good intentions must be followed up by meaningful action on the subjects of accountability and stewardship of revenue collection related to Alberta's oil, natural gas and bitumen. This is true not only immediately, but for as long as natural resources remain to be extracted from this territory. The size and importance of the energy resource to Alberta makes this need both urgent and enduring.



The accountability framework would require, at a minimum, that the following reports be submitted to the Legislature and not merely filed internally to the Minister of Energy:

- Effectiveness audits every two years, and
- Annual reports to the owners comprising professional and comprehensive technical, economic and business data, and
- Quarterly statistics on production, prices, developer operating and capital costs (since Albertans allow costs to be deducted before calculating Royalties), collection amounts and forecasts. One starting point for the standards such reporting ought to meet could be the Revenue Source Book of Alaska.

If the Panel's suggested enforcement, public reporting function and accountability culture are not created now, with unwavering commitment from the Government's leadership, one can only hope for a response when the current extent of "data vacuum" and seeming absence of oversight becomes more obvious and more acute to the public at large, as it has to the Panel in the course of its review.

In putting forward these proposals, the members of the Royalty Review Panel express the sincere hope that their recommendations will provide a solid foundation for continuous improvement in Alberta's energy royalty system in the years to come. We believe that, with better information and public awareness of such information, the royalty system can and will become both more accountable and more effective, to the lasting benefit of the people of Alberta.

## TERMS OF REFERENCE - SUMMARY OF RESPONSES

*The terms of reference for the Alberta Royalty Review Panel are available at: [http://www.albertaroyaltyreview.ca/panel/newsrel\\_2007\\_0216.pdf](http://www.albertaroyaltyreview.ca/panel/newsrel_2007_0216.pdf) The terms of reference are reproduced below, with the Panel's summary response to each in indented text.*

### **Royalty Review Terms of Reference**

An independent Panel of experts will review all aspects of the oil and gas royalty system, including conventional and oil sands. The Panel will also examine the tax regime faced by resource companies, including income tax and the freehold mineral rights tax levied on freehold mineral rights holders.

### **Terms of Reference**

The Premier has heard from Albertans and has given the Finance Minister the mandate to "conduct a public review to ensure Albertans are receiving a fair share from energy development through royalties, taxes and fees."

To the question "are Albertans getting a fair share?" the answer is "no". Alberta's percentage take from energy development has dropped over the past decade, both absolutely and relative to other energy-producing jurisdictions. Royalties should be increased overall, and rebalanced fairly between high, low, old and new production.

The Finance Minister is appointing an independent expert Panel to consult with Albertans and provide recommendations for the government's consideration. Some of the issues the Royalty Review Panel has been asked to consider:

- How Alberta's royalty system compares to other oil and gas producing jurisdictions, taking into account investment economics and industry returns and risks in Alberta

Taking into account investment economics, industry risks and returns, Alberta's royalty system produces a smaller take for Albertans than



comparable systems around the world. Alberta can raise its royalties and still compete effectively for investment with other energy-producing areas.

- Whether Alberta's royalty system is sufficiently sensitive to market conditions.

Alberta's royalty rate caps have not kept pace with rising energy prices, with the effect that the current system is no longer sufficiently sensitive to market conditions. The recommended royalty formulas will reinstate price sensitivity.

- Whether the current revenue minus cost system for oil sands royalties is optimal.

The current system of revenue minus cost (R-C) is sound for oil sands. However, the net royalty rate needs to be adjusted, and a severance tax added, to ensure a reasonable return to the resource owner (Albertans). The definitions of allowable costs need to be tightened and enforced, and transparency issues with bitumen pricing need to be addressed for the system to perform as intended.

- Which programs built into the existing royalty system should be retained or strengthened, and which should be adapted or eliminated.

Programs to encourage R&D should be retained, provided they are time/dollar limited. Many programs were designed to compensate for production characteristics or market insensitivity of royalty rates. With the proposed new royalty formulas these programs will no longer be necessary. A new program is suggested to encourage the location of new upgrading capacity in Alberta.

- How the tax treatment of the oil and gas sector compares to other sectors and jurisdictions.

Oil and natural gas has received many advantages not available to other sectors, but also pays royalties which non-resource sectors do not pay. The oil and natural gas sector in Alberta has a tax treatment advantage over other sectors in the economy.

- The economic and fiscal impacts of any possible changes to the royalty and corporate tax systems

The proposed increase in royalties and taxes will slow the rate of investment in the oil sands, not as a primary goal, but as a result of re-establishing a fair share for Albertans. The reduction of royalties for the majority of natural gas and conventional oil wells that are low production will re-balance economic activity.

- How existing resource development should be treated if changes are made to the fiscal regime.

The Panel recommends that no "grandfathering" be allowed. New rules should apply to all, without exception.

## **THE CHAIRMAN'S AFTERWORD**

Now, at the end of this task and looking back, I am struck by how much of our discussions revolved around exploring appropriate ways to respond to the many concerns voiced for the environment resulting from the pace of development.

We were privileged to hear from many shareholders (Owners) and stakeholders (Developers) of the non-renewable resource on the subject of the environment.

The Owners were adamant that the environment is to be protected for generations to come; the stakeholders agree and implement company policy to accommodate. The Owners are concerned that the high rate of development is an issue that has significant implications on the environment; the Owner also expects maximum value for its natural resources. The Developer, by project, is legally bound to meet the regulatory standards of protection and is diligent to perform.

We heard the Owners say they felt the royalty regime should incorporate some mechanism to accommodate environmental risks and mitigation with an increase in royalty revenues. The Developers agreed that environmental due diligence is important and that other mechanisms of environmental performance are preferred, i.e. license to operate, environmental regulation, etc.

We deliberated over all the submissions and inputs and came to the following conclusions:

- A healthy environment is a critical indicator of the ability for government to manage resource development in this Province.
- The Royalty Regime is not the vehicle to accommodate environmental protection and mitigation.
- The government must enforce and measure effectiveness of current regulation, legislation and policy through license to operate, pollution abatement and cumulative effects monitoring.

In our examinations of these submissions and investigation of the issues they raise, these points stood out:

- Alberta is blessed with an abundance of renewable and non-renewable resources extracted from Crown Land (Owners' lands) with varying degrees of impact on the environment, collectively a significant footprint. That is to say, this is not a matter confined to energy, it touches all land use.
- Many states in the US and other countries have encountered the same issues and opportunities around the environment. Many have introduced a Conservation Tax ("CT") as a mitigation strategy.
- Conservation taxes are used to:
  - Create multi-stakeholder long term planning bodies that focus on future generations
  - Build preservation and rehabilitation mitigation strategies
  - Invest in renewable energy research and technologies.

We on the Panel became convinced that the environment is a critical component in planning our future. Perhaps this review of royalty policy presents an opening for the public and government to explore these opportunities and move further to accommodate the growing public consensus.

In this spirit, we include a final thought as a talking point for how the world of money and of the environment might come together in Alberta's future:

*Alberta could implement a Crown Land Conservation Tax (CLCT), which would allow a multi-stakeholder body (a Board) to analyze, assess and plan strategies and tactics to protect the environment for future generations. All sectors that benefit from utilization of natural resources on Crown Lands would be taxed and share in the opportunity to secure our environment.*

*Tax charge implications would be based on sector and resource, for example:*

- Conventional oil, natural gas and bitumen would be charged \$0.10 per BOE (barrel of oil equivalent),
- Forestry at \$0.25 per cubic meter of timber logged,
- Mining at \$0.10 per tonne extracted,
- Agriculture at \$10.00 an acre for crown land occupation.

*In total, this would raise approximately \$75 million per year; significant revenues to fund a variety of pro-active, multi stakeholder managed research and innovation programs directed to promote a well thought through future. In a realm where billions of dollars are risk and made, a portion would be set aside; directed to a cause many Albertans think is vital for obtaining our continued consent for resource development.*

